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# Oxides of Nitrogen/Ammonia Control Technology for Oil Shale Retort Emissions

Monsanto Research Corp., Dayton, OH

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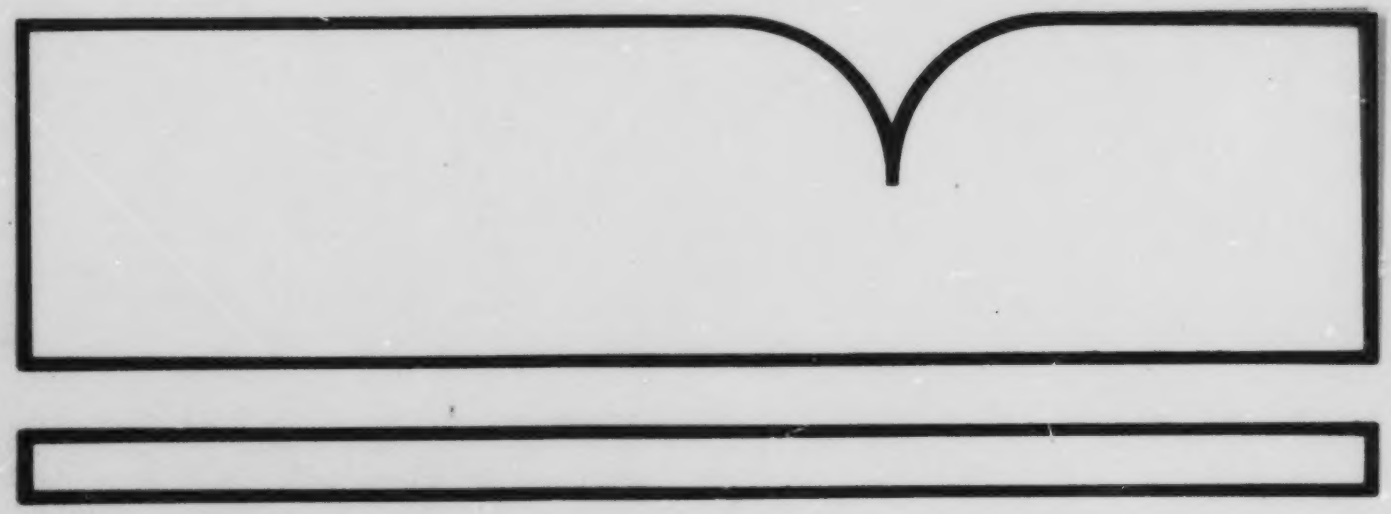

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# OXIDES OF NITROGEN/AMMONIA CONTROL TECHNOLOGY FOR OIL SHALE RETORT EMISSIONS

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16. ABSTRACT
The retorting of oil shale yields several undesireable pollutants. The nitrogen in the shale and the reducing conditions under which the retorting is carried out results in the formation of sizeable amounts of ammonia in the gas stream. If not removed, the ammonia will make a significant contribution to the $NO_x$ emissions after the gas is burned.

The projected $NO_x$ emissions from five selected oil shale developers were modeled using the VALLEY air dispersion model and found that the levels of $NO_x$ were increased near the plant sites but dropped off to just above baseline at a distance of 6 km. Additional projections of $NO_x$ impact on the ambient air impact were also made as a result of modifying the combustion conditions and use of Selective Catalytic Reduction control technology. Both of the additional control technology options corresponded to tighter air pollution regulations. It was concluded that oxide of nitrogen emissions would not be a significant air pollution problem in the development of the oil shale industry.

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# SECTION 1

# INTRODUCTION

Interest in the recovery of oil from shale has increased during the past decade as oil production in the United States has continued to fall behind domestic demand. Oil shale development can assist the United States in becoming less dependent on foreign oil. However, the development of the vast oil shale deposits in the Western states is not without risks. The developers must not only design and optimize new processes but must also be aware of potential environmental changes in the near-pristine areas where shale is found. To help reduce environmental effects in these areas, the U.S. Environmental Protection Agency (EPA) is currently evaluating appropriate control technologies for several potential pollutants.

As part of this EPA effort, Monsanto Research Corporation (MRC) under EPA Contract No. 68-03-3025 has studied the pollution potential and control of nitrogen oxides/ammonia ($NO_x/NH_3$) from oil shale retorting operations. The primary objectives of this study were to collect the available data on $NO_x/NH_3$ emissions from oil shale retorting operations, define the $NO_x/NH_3$ pollution potential from oil shale development on the surrounding area, to determine available control technology to control these emissions, and to design a mobile pilot plant (~1,000 scfm) that may later be built and used in the field to establish the control effectiveness of the selected technology. This interim report presents estimates for the ambient $NO_x$ concentrations resulting from five planned developments in the Piceance Basin and recommendations for

technologies for $NO_x/NH_3$ control. Rationale for these recommendations is also presented. The final design phase of the project was expected to commence upon approval of this selection by the EPA project officer.

As discussed later, the $NO_x$ emissions do not pose a serious problem; therefore, we decided not to design and construct a pilot $NO_x$ control device for research purposes.

Section 2 is a summary of the conclusions reached in this report. Recommendations are presented in Section 3. Section 4 describes the general pollution potential due to oil shale development in the Piceance Basin. The selection of the best type of control is discussed in Section 5 including the selection criteria used, the technologies considered and the rationale behind the selection. Uncertainties of this selection are also discussed.

## SECTION 2

## SUMMARY

The VALLEY air dispersion model was used to qualitatively predict the nitrogen oxides ($NO_x$) pollution potential from five selected oil shale developments currently being planned. The $NO_x$ contributions from these facilities were added to the median background concentration of 9 $\mu g/m^3$ and the total was found to be within the National Ambient Air Quality Standard (NAAQS) of 100 $\mu g/m^3$ except for isolated points. Most developments have a small area surrounding the plant site where the $NO_x$ concentration exceeds 50 $\mu g/m^3$ but this level drops rapidly as the distance from the plant increases. In most instances, the concentration drops below 5 $\mu g/m^3$ at a distance of 6 km from the site.

Although the $NO_x$ pollution potential meets the current NAAQS, new standards to prevent significant deterioration are being evaluated by the EPA for promulgation. Since those standards have not been established and minimal information is available concerning these, it is difficult to predict what concentration increments will be acceptable. To adequately describe the possibilities, three control scenarios have been proposed.

The first scenario evaluates the need for $NO_x$ control based on the current NAAQS. The results of the modeling, discussed above, indicate that no control is currently needed. This conclusion is predicted upon the basis that the full-scale oil shale retort operations include ammonia recovery as one of the off-gas treating processes.

Ammonia concentration in the off gas can be reduced by approximately 85 percent using a water scrubbing system or up to 99 percent if an acidic scrubber using sulfuric acid is used. This ammonia reduction eliminates the fuel nitrogen in the off-gas and reduces the potential $NO_x$ ambient concentration below the current NAAQS.

The second scenario proposes that a PSD increment which is 25% of the $NO_x$ NAAQS be evaluated. This proposed increment is proportional to the increments which have already been promulgated for sulfur dioxide and particulate matter which are 25% of the respective NAAQS. Using this proposed increment, the permissible concentration contribution desired is 25 $\mu g\ NO_x/m^3$. This would require an approximate 50% reduction in the current emission rates based on the air dispersion modeling. Combustion modification techniques, although not feasible for pilot-scale construction and testing, can achieve this reduction.

The third scenario is based on control of 90% of the $NO_x$ emissions from the major sources. Flue gas treatment can achieve this removal. Eleven $NO_x$ control technologies were considered, including six that could control $NO_x$ and sulfur dioxide simultaneously. These technologies were evaluated for applicability, development status, removal efficiency, relative econimics, and water usage. Table 1 presents a summary of the five best technologies according to this evaluation. The best type of flue gas treatment that was selected after applying these criteria is selective catalytic reduction using a parallel flow reactor. This control technology, which is currently in use in Japan, is capable of removing over 90% of the $NO_x$ from oil-fired boilers, is not affected by large particulate loadings, and is more economical than scrubbing processes.

TABLE 1. FIVE PREFERRED $NO_x$ FLUE GAS TREATMENT TECHNOLOGIES [1, 2]

| Technology | Applicability | Status of development | Removal efficienty | Economics | Water usage | Rating |
|---|---|---|---|---|---|---|
| Selective catalytic reduction by parallel flow reactor | Applicable | Full scale, in use | >90% | Fixed cost: $10,800/GJ/hr<br>Operating cost: 420 mills/GJ | Minimal | Good |
| Selective catalytic reduction by moving bed reactor | Applicable | Full scale, in use | >90% | Fixed cost: $19,400/GJ/hr<br>Operating cost: 500 mills/GJ | Minimal | Good |
| Selective catalytic reduction by parallel flow reactor for simultaneous $SO_x/NO_x$ removal | Applicable | Full scale, tests only | >90% $NO_x$<br>>90% $SO_x$ | Fixed cost: $130,000/GJ/hr<br>Operating cost: 1,400 mills/GJ | Minimal | Fair |
| Selective catalytic reduction by fixed-bed reactor | Applicable with particulate removal | Full scale, in use | >90% | Fixed cost: $19,400/GJ/hr<br>Operating cost: 530 mills/GJ | Minimal | Fair |
| Selective noncatalytic reduction | Applicable | Full scale, in use | 40-60% | Fixed cost: $8,900/GJ/hr<br>Operating cost: Unknown | Minimal | Fair |

## SECTION 3

## RECOMMENDATIONS

It is recommended that the selection of the parallel flow SCR reactor be approved for design of a 1,000 scfm pilot plant. This recommendation is based on the anticipated PSD regulations that may require $NO_x$ control on oil shale retorting processes. In addition, combustion modification techniques should be evaluated to determine applicability and $NO_x$ removal efficiency. This investigation may be conducted on a full scale basis at the retort sites or at research facilities equipped with combustion modification pilot plants and supplied with oil from shale for testing. Such an investigation may indicate that combustion modification techniques can adequately control $NO_x$ emissions and may eliminate the need for more expensive flue gas treatment.

## SECTION 4

## POLLUTION POTENTIAL OF NITROGEN OXIDES

A fundamental criterion for selecting an appropriate control device for any pollutant is the amount of control that is necessary to comply with applicable regulations. In order to determine the level of control required of an $NO_x$ control technique applicable to the oil shale industry, it was necessary to estimate the ambient level of $NO_x$ that would result from processing oil shale. This was accomplished for a hypothetical first-generation oil shale industry in the Piceance Basin by modeling the estimated emissions from five planned developments in the area. These five developments are listed in Table 2 along with the retorting processes to be used and the predicted production of each facility. Table 3 lists the estimated $NO_x$ emissions from each facility.

### AIR DISPERSION MODELING [3]

The EPA VALLEY model was used to predict the incremental increase in $NO_x$ ambient levels that would result from the operation of the five developments listed in Table 2. The VALLEY model has the capability for modeling rough terrain areas, stable and unstable weather conditions, and multiple emission sources. It can be used to predict annual or 24-hour averaged levels and can take into account the reactivity of a pollutant species in the atmosphere [3].

TABLE 2. FIRST-GENERATION OIL SHALE INDUSTRY

| Development | Retorting process (method) | Production rate |
|---|---|---|
| Colony Development Operation [4] | TOSCO II (surface, indirect heating) | 46,000 bbl/day |
| Cathedral Bluffs Shale Oil Company[a] | Occidental MIS (modified in-situ), and Lurgi (surface, indirect heating) | 117,000 bbl/day |
| Rio Blanco Oil Shale Company | Lurgi[b] (surface, indirect heating) | 50,000 bbl/day |
| Long Ridge Experimental Shale Oil Project [5] | Union Retort B (surface, indirect heating) | 50,000 bbl/day |
| Superior Oil Company [6] | Circular Grate Retort (surface, indirect heating) | 11,500 bbl/day |

[a]Personal communication with R. Fischer, EPA Region VIII, April 14, 1981.

[b]Rio Blanco has not yet decided on Lurgi, MIS, or a combination of the two for commercial development. For the purposes of this study it is assumed Lurgi will be used along with MIS for a combined production of 50,000 bbl/day.

[c]Personal communication with K. Berry, Rio Blanco Oil Shale Company, March 11, 1981.

TABLE 3. ESTIMATED $NO_x$ EMISSIONS FROM OIL SHALE DEVELOPMENTS

| Process | Colony Development Operation [4] (kg/hr) | Cathedral Bluffs Oil Shale Company [5] (kg/hr) | Rio Blanco Oil Shale Company[a] (kg/hr) | Long Ridge Experimental Shale Oil Project [7] (kg/hr) | Superior Oil Company [6] (kg/hr) |
|---|---|---|---|---|---|
| Preheat stacks | 597.0 | NA | NA | NA | NA |
| Cold ball elutriators | 6.4 | NA | NA | NA | NA |
| H2 furnaces | 37.3 | NA | NA | NA | NA |
| Naphtha heaters | 0.6 | NA | NA | NA | NA |
| Gas oil heaters | 1.2 | NA | NA | NA | NA |
| Gas oil reboiler | 5.1 | NA | NA | 3.4 | NA |
| Coker feed heater | 3.8 | NA | NA | NA | NA |
| Boiler | 9.8 | NR | NR | 43.1 | 19.1 |
| Utility boilers | 0.4 | NR | NR | NR | NR |
| Recycle gas heater | NA | NA | NA | 147.0 | NR |
| Retort vent stack | NA | NA | NA | 0.1 | NA |
| Vapor disposal | NR | NR | NR | 0.9 | NR |
| Flare pilot | NR | NR | NR | 0.1 | NR |
| Mineral kilns | NA | NA | NA | NA | 10.4 |
| Diesel exhaust | NR | NR | NR | NR | 8.1 |
| Mine vent | 113.0 | 9.3 | 4.2 | NR | 39.6 |
| Lurgi flue gas stacks | NA | 38.5 | 17.5 | NA | NA |
| Flue gas desulfurization | NA | 242.0 | 110.0 | NR | NR |
| Blasting | NR | NR | NR | 30.6 | NR |
| Temporary power generator | NA | 0.4 | 0.2 | NA | NA |
| Cement plant bath boiler | NA | 0.0 | 0.0 | NA | NA |
| TOTAL | 820.0 | 291.0 | 139.0 | 225.0 | 77.2 |

Note: NA - Not applicable; process not used at development. NR - Not reported; process may be used by development but $NO_x$ emissions were not reported.

[a]Values estimated by comparing production rates of Rio Blanco with Cathedral Bluffs.

The dispersion equations used in the VALLEY model have been developed from the familiar bivariate Gaussian formulation which describes the dispersion of a pollutant from a point source. One of the two dispersion equations used in the VALLEY model is [3]:

$$\chi(x,y,o;h,L) = 2.03 \cdot 10^{6}\, Q\, K\, ([c-y]/c)\, ([401-D]/400)C \cdot \sum_{N=-J}^{+J} \exp\{-0.5\,[(H+2\,N\,L)/\sigma_z]^2\} \cdot \{\exp[-(0.693\, x_p)/(3600\, u\, I)]\}/(\sigma_z\, u\, x) \quad (1)$$

where $\chi$ = concentration in micrograms per cubic meter ($\mu g/m^3$) or parts per million (ppm), always calculated at ground level

$x$ = the source-receptor distance (m), as projected on the mean wind vector through the source

$y$ = the crosswind distance (m) of the receptor from a line parallel to the mean wind drawn through the source; $y \leq c$

$H$ = plume centerline height (m) above the receptor; the receptor is always at ground level. Plume height $h_o$ above the stack base is calculated internally, and then may be adjusted for terrain elevation at the receptor to provide H. For nonstable conditions, or over flat terrain, $H=h_o$

$L$ = mixing height (m) above ground; L remains constant, regardless of topography

$Q$ = the pollutant emission rate (g/s) of a given source, averaged over the period of concern

$c$ = the crosswind arc length of the 22.5° wind sector implicit in this formulation

$D$ = receptor elevation minus plume height, each in meters above mean sea level. The D term simulates the stable-case deflection by terrain of the plume from the sector being evaluated

$1\ m < D \leq 401\ m$ {stable conditions}

$D = 1\ m$ {neutral and unstable conditions}

C determines the units of x:

$C = 1$ {for $\chi$ in $\mu g/m^3$; required for nongaseous pollutants}

$C = 0.0831\ T/(M\ P)$ {for gases only, to obtain $\chi$ in ppm}

where T = ambient air temperature ($^{o}K$)

M = molecular weight of the gas (grams per mole)

P = ambient air pressure (millibars)

K converts concentrations from on-site to standard conditions of temperature and pressure. $K = 1013.2\ T/(298\ P)$.

N = The number of perfect reflections a parcel of air has undergone before reaching the distance of the receptor. The limits on N determine the accuracy of the term

$\sigma_z$ = the standard deviation (m) of the vertical Gaussian distribution of the pollutant and $\sigma_z = f(x)$

$x_p$ = the distance (m) from the receptor to the point source or to the center of the area source projected to the mean wind direction as was defined for x; for point sources, $x_p = x$

u = the mean wind speed (m/s) affecting the plume

I = the half-life (hr), of the pollutant and the exponential containing I is the half-life factor

In the VALLEY model, $J \leq 5$. However, as $\sigma_z$ becomes large relative to L, this low limit on J can result in serious underestimates of $\chi$. The error can be reduced to insignificance by equating J to a large value, but with a corresponding increase in computation time. Fortunately, a simple approximation to Equation 1 exists for these conditions; for distances beyond which $\sigma_z = 2\ L$ the VALLEY model uses a second equation in the form [3]:

$$\chi(x,y,o;h,L) = 2.55 \cdot 10^6\ Q\ K\ ([c-y]/c)\ ([401-D]/400)\ C \cdot \{\exp[-(0.693\ x_p)/(3600\ u\ I)]\}/(L\ u\ x) \qquad (2)$$

This simple equation provides a very good approximation to Equation 1 when J is very large and the vertical distribution of pollutants has become virtually homogeneous.

Five types of data are required as input for the VALLEY model: emission rates, meteorological data, stack parameters, receptor data, and a pollutant atmospheric reaction constant. The emission rates that were used as input to the model are listed in Table 3. These data which define pollutant contributions were obtained from the literature [4-7] except for Rio Blanco Oil Shale facility for which values were proportionally estimated by comparing production rates with Cathedral Bluffs. This assumption was based on the similarity of processes used at the two facilities. Also, as shown in Table 3, some processes report no $NO_x$ emissions which could result in an underestimation of pollutant concentrations. However, by comparing with processes at other developments, the $NO_x$ concentration contributed by these processes appears to be small when compared to other $NO_x$ sources and will only marginally affect the results reported.

Meteorological data include stability-wind rose data (STAR data), the annual average mixing height, and ambient temperature. The STAR data are the frequencies of occurrence of six wind speed classes by sixteen wind directions by six stablity categories (A to F) and define the transport and the degree of dispersion of the pollutant. The STAR data, presented in Appendix A, were only available for two developments: Rio Blanco and Long Ridge. These data, as shown in Appendix A, were used as input data for the remaining developments based on topographic and expected climatological similarity, i.e., Rio Blanco data were used as input for modeling Cathedral Bluffs and Colony, and Long Ridge data were used for Superior.

The mixing height determines the altitude through which the pollutant may be mixed before being totally reflected downward. The annual average mixing height of 2600 m at Grand Junction, Colorado was chosen for all five facilities based on the recommendation of Roger Tucker (U.S. Department of Interior). Personal communication from Roger Tucker, USGS, 27 February 1981 to D. W. Dunn.

Stack parameters (stack height and diameter, and gas flow rate, exit velocity, and temperature) were available in the literature for all but the Rio Blanco and Superior developments. The stack parameter data for these two developments were proportionally estimated through comparison with similar processes in the other developments. Tables 4 through 8 list the stack parameters for each development. Four out of five developments have no available plant-site layouts. Therefore, all stacks were assumed to be located at a central point in the development to give a worst-case estimation.

For receptor data, a network of 112 receptors is established by the model. These were controlled by two factors relative to the network: (1) the geographic spacing of the receptors, through a scaling factor; and (2) the vertical spacing of the receptors through assignment of the terrain elevation at each receptor.

The nitrogen oxide reaction constant was assumed to equal a half-life of 24 hours based on the literature [8] and prior experience by EPA Region VIII. Half-life used in this context is the period of time that the pollutant concentration in a given parcel of air is reduced 50 percent by transformation of the pollutant. This should not be confused with the dilution of diffusion of the pollutant. Nitrogen oxides in the atmosphere tends to photochemically react with other species, such as ozone ($O_3$) and hydrocarbons, which results in a net reduction in their concentrations [9].

TABLE 4. STACK PARAMETERS - COLONY DEVELOPMENT OPERATION[a] [4]

| Process | Number of stacks | Stack height, m | Stack diameter, m | Gas volume flow rate, $m^3/s$ | Gas exit velocity, m/s | Gas exit temperature, °K |
|---|---|---|---|---|---|---|
| Preheat stacks | 6 | 94.5 | 2.84 | 100 | 15.8 | 326 |
| Cold ball elutriators | 6 | 94.5 | 1.37 | 21.0 | 14.2 | 357 |
| $H_2$ furnaces | 4 | 24.4 | 1.75 | 36.8 | 15.2 | 500 |
| Naphtha heaters | 1 | 22.9 | 0.76 | 3.33 | 7.32 | 700 |
| Gas oil heaters | 2 | 22.9 | 0.76 | 4.87 | 10.7 | 755 |
| Gas oil reboiler | 1 | 45.7 | 1.75 | 26.5 | 11.0 | 644 |
| Coker feed heater | 1 | 53.3 | 2.29 | 18.8 | 4.57 | 450 |
| Boiler | 2 | 16.8 | 2.13 | 27.3 | 7.62 | 477 |
| Utility boilers | 2 | 4.6 | 0.38 | 0.59 | 5.18 | 505 |
| Vapor disposal | NR | NR[b] | NR | NR | NR | NR |
| Flare pilot | NR | NR | NR | NR | NR | NR |
| Diesel exhaust | NR | NR | NR | NR | NR | NR |
| Mine vent[c] | 1 | 4.6 | 1.52 | 29.5 | 16.2 | 289 |
| Flue gas desulfurization | NR | NR | NR | NR | NR | NR |
| Blasting | NR | NR | NR | NR | NR | NR |

[a]Personal communication to G. M. Rinaldi with C. S. Waitman, Arco Coal Company, Colony Development, 22 February 1980.

[b]NR = not reported; process may be used by the development, but stack parameters are not reported in the literature.

[c]Values estimated by using stack parameters of primary crusher.

TABLE 5. STACK PARAMETERS - CATHEDRAL BLUFFS OIL SHALE COMPANY[a]

| Process | Number of stacks | Stack height, m | Stack diameter, m | Gas volume flow rate, $m^3/s$ | Gas exit velocity, m/s | Gas exit temperature, °K |
|---|---|---|---|---|---|---|
| Boiler | NR[b] | NR | NR | NR | NR | NR |
| Utility boilers | NR | NR | NR | NR | NR | NR |
| Vapor disposal | NR | NR | NR | NR | NR | NR |
| Flare pilot | NR | NR | NR | NR | NR | NR |
| Diesel exhaust | NR | NR | NR | NR | NR | NR |
| Mine vent | 2 | 30 | NR | 16.8 | 19.1 | 294 |
| Lurgi flue gas stacks | 8 | 30 | 3.15 & 2.57[c] | 190 & 285[c] | 36.6 | 433 |
| Flue gas desulfurization | 5 | 30 | 4.71 | 637 | 36.6 | 346 |
| Blasting | NR | NR | NR | NR | NR | NR |
| Temporary power generator | 1 | 6.1 | 0.85 | 113 | 200 | 845 |
| Cement plant bath boiler | 1 | 5.5 | 0.51 | 3.21 | 15.7 | 589 |

[a]Personal communication with R. Fischer, EPA Region VIII on 14 April 1981.

[b]NR = not reported; process may be used by the development, but stack parameters are not reported in the literature.

[c]The first number is for Lurgi flue gas stacks 1, 4, 5, and 8; the second number is for stacks 2, 3, 6, and 7.

TABLE 6. STACK PARAMETERS - RIO BLANCO OIL SHALE COMPANY[a]

| Process | Number of stacks | Stack height, m | Stack diameter, m | Gas volume flow rate, $m^3/s$ | Gas exit velocity, m/s | Gas exit temperature, °K |
|---|---|---|---|---|---|---|
| Boiler | NR[b] | NR | NR | NR | NR | NR |
| Utility boilers | NR | NR | NR | NR | NR | NR |
| Vapor disposal | NR | NR | NR | NR | NR | NR |
| Flare pilot | NR | NR | NR | NR | NR | NR |
| Diesel exhaust | NR | NR | NR | NR | NR | NR |
| Mine vent | 1 | 30 | NR | 13.8 | 18.2 | 294 |
| Lurgi flue gas stacks | 2 | 30 | 3.1 | 236 | 31.2 | 433 |
| Lurgi stack | 2 | 30 | 2.5 | 153 | 31.2 | 433 |
| Flue gas desulfurization | 2 | 34 | 4.7 | 541 | 31.2 | 346 |
| Blasting | NR | NR | NR | NR | NR | NR |

[a]Proportional estimates from Cathedral Bluffs Oil Shale Company. Both developments are planning similar operations.

[b]NR = not reported; process may be used by the development, but stack parameters are not reported in the literature.

TABLE 7. STACK PARAMETERS - LONG RIDGE EXPERIMENTAL SHALE OIL PROJECT [10]

| Process | Stack height, m | Stack diameter, m | Gas volume flow rate, $m^3/s$ | Gas exit velocity, m/s | Gas exit temperature, °K |
|---|---|---|---|---|---|
| Gas oil reboiler | 22.9 | 0.50 | 15 | 19.1 | 664 |
| Boiler | 22.9 | 1.68 | 21 | 9.51 | 639 |
| Utility boilers | NR[a] | NR | NR | NR | NR |
| Recycle gas heater | 61 | 2.25 | 74.4 | 18.8 | 811 |
| Retort vent stack | 7.8 | 1.0 | 10 | 12.7 | 327 |
| Vapor disposal | 7.8 | 1.0 | 25 | 31.8 | 289 |
| Flare pilot | 7.8 | 1.0 | 5 | 6.37 | 327 |
| Diesel exhaust | NR | NR | NR | NR | NR |
| Mine vent | NR | NR | NR | NR | NR |
| Lurgi flue gas stacks | NR | NR | NR | NR | NR |
| Flue gas desulfurization | NR | NR | NR | NR | NR |
| Blasting | 15.2 | 3.4 | 250 | 27.5 | 289 |

[a]NR = not reported; process may be used by the development, but stack parameters are not reported in the literature.

TABLE 8. STACK PARAMETERS - SUPERIOR OIL COMPANY[a]

| Process | Stack height, m | Stack diameter, m | Gas volume flow rate, $m^3/s$ | Gas exit velocity, m/s | Gas exit temperature, °K |
|---|---|---|---|---|---|
| Boiler | 22.9 | 1.68 | 9.28 | 4.21 | 639 |
| Utility boilers | NR[b] | NR | NR | NR | NR |
| Recycle gas heater | NR | NR | NR | NR | NR |
| Vapor disposal | NR | NR | NR | NR | NR |
| Flare pilot | NR | NR | NR | NR | NR |
| Mineral kilns | | | | | |
| Nachohlite | 22.9 | 0.91 | 2.64 | 4.02 | 555 |
| Alumina | 22.9 | 0.91 | 1.88 | 2.87 | 600 |
| Lime | 15.2 | 0.61 | 0.52 | 1.77 | 566 |
| Diesel exhaust | NR | NR | NR | NR | NR |
| Mine vent | 4.6 | 1.52 | 9.77 | 5.36 | 289 |
| Lurgi flue gas stacks | NR | NR | NR | NR | NR |
| Flue gas desulfurization | NR | NR | NR | NR | NR |
| Blasting | NR | NR | NR | NR | NR |

[a]Parameters estimated by comparison to similar processes at other developments.

[b]NR = not reported; process may be used by the development, but stack parameters are not reported in the literature.

Certain limitations must be considered when using the application of the VALLEY model [3]. These limitations are as follows:

1. Accuracy is considered to be within a factor of 2 (plus 100 percent or minus 50 percent).

2. The range over which the model can give accurate concentration estimates is no more than a few kilometers. This distance is dependent on the climatogic and topographic condition in the area. Plume behavior during horizontal transport is not well known beyond that variable distance. In this study, we have extended travel distance to about 7 kilometers in order to model the decreasing $NO_x$ concentration as distance increases. This distance appears reasonable for normal use of the VALLEY model but may be on the outer limits of accuracy because of the surrounding terrain. An exponential increase of standard deviation of the vertical dispersion during strong unstable stability categories, may cause an underestimation of pollutant concentration beyond this limit and may affect the modeling results even within these limits at certain receptors.

3. The model is not designed to estimate concentrations during unusual meteorological conditions such as aerodynamic downwash and fumigation which may occur during upslope and downslope wind conditions.

4. A straight-line transport of pollutants is assumed by the model. Hence, curvature of the plume due to pressure gradients, induced by topographic features is not simulated by the model. Since the Piceance basin area is a highly complex terrain where curvature of the plume is not expected to be unusual, an underestimation of pollutant concentration using the VALLEY model could occur in areas where large variations in elevation occur in short distances.

5. The use of observed surface meteorological data to describe the transport and dispersion of pollutants from elevated sources during stable conditions in complex terrain is likely to involve a source of error in the application of VALLEY model.

   In this study, we have used two sets of meteorological data, i.e., Rio Blanco and Long Ridge, to model all five developments. These two sets were the only data available at this time. However, in the complex terrain, the meteorological conditions can be quite different, even though topography of the areas is similar. If these data are used as input to the VALLEY model, an error in the estimation of pollutant concentration results.

6. Estimated average emission rate data based on literature value (Table 3) were used as the VALLEY input in this study. However, significant diurnal and seasonal variations in emission rates occur and can influence the levels of ambient pollutant concentrations.

7. The VALLEY model limits the modeling to 112 receptors. These receptors are located by the program and cannot be placed at specific points of interest. As a result, the maximum concentration attainable may not fall at any of the 112 receptors modeled.

8. If the plume height only slightly exceeds the surrounding terrain and/or the source itself lies in the lee of a hill, the pollutants may be drawn downward by down drafts in the lee of the crest and create a pollution problem at ground level. The VALLEY model does not simulate these situations.

9. When a plume centerline height reaches a point where it exceeds the mixing height, the contribution of that plume to all ground-level receptors downwind of that point is considered zero.

10. The discontinuities caused by the description of meteorological conditions by step functions, i.e., discrete classes, are smoothed in the VALLEY model across wind direction classes only. This "smoothing" causes some potential problems that may erroneously influence the model results both positively or negatively.

## MODELING RESULTS

The modeling results that were obtained in this study are illustrated in Figures 1-5. The isopleths represent varying incremental annual average concentrations of $NO_x$ that will result from the operation of the five modeled oil shale developments. An $NO_x$ concentration greater than 50 $\mu g/m^3$ but less than 100 $\mu g/m^3$ occurs near each site. The concentration does not exceed the $NO_x$ NAAQS of 100 $\mu g/m^3$ and generally decreases to less than 5 $\mu g/m^3$ at a distance of 6 km from the source. Since most of the developments are over, generally, 12 km apart, only small additive effects would occur between adjacent sites, except for Colony and Long Ridge which share a common land boundary. No estimate is presented for the potential effect on the Flat Tops Wilderness Area, the nearest area designated a Class I by the PSD regulations because of the large distance (approximately 50 km) separating it from the nearest development. The concentrations shown in Figure 1 do not include background ambient $NO_x$ concentrations which have been reported to be approximately 10 $\mu g/m^3$ [11].

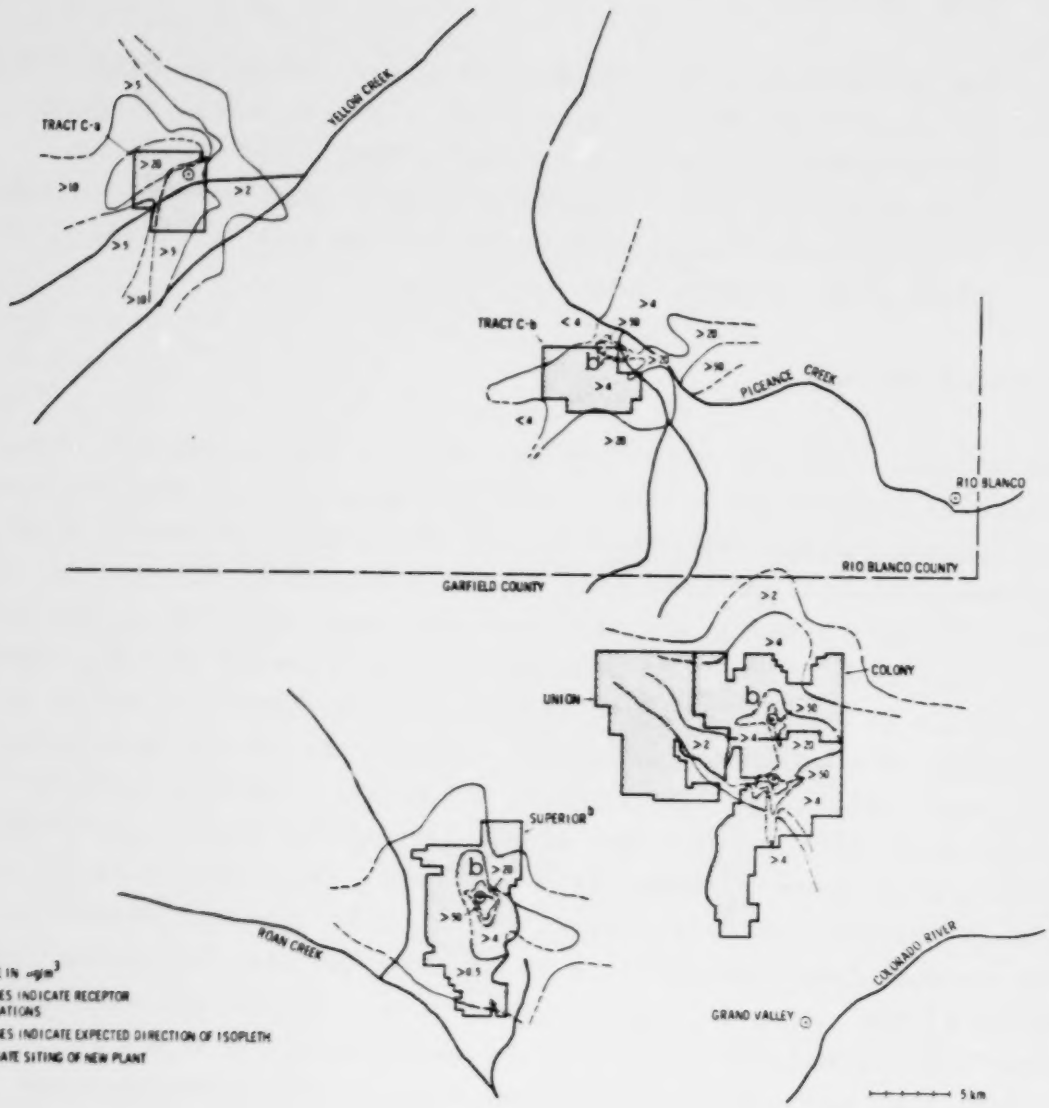
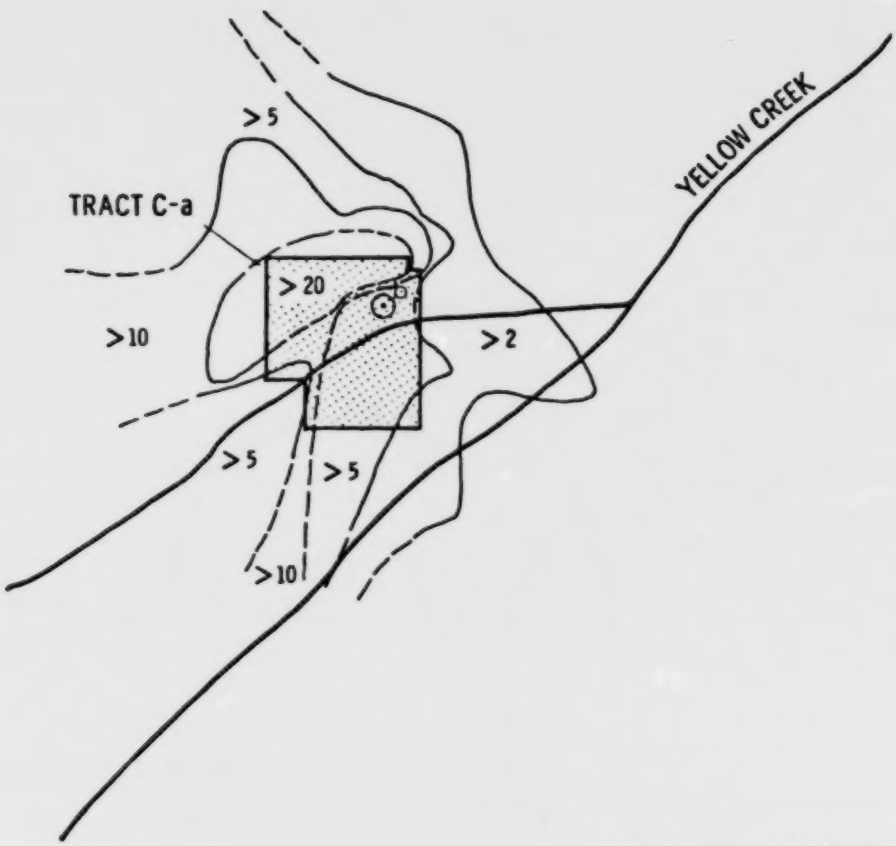



Figure 1. Estimated $NO_x$ ambient concentrations resulting from oil shale processing in the Piceance Basin.[a]

[a]Does not include the present ambient level.




VALUES ARE IN $\mu g/m^3$

SOLID LINES INDICATE RECEPTOR CONCENTRATIONS

DASHED LINES INDICATE EXPECTED DIRECTION OF ISOPLETH

[b]APPROXIMATE SITING OF NEW PLANT

Figure 2. Estimated $NO_x$ ambient concentrations resulting from Tract C-a (Rio Blanco Oil Shale Company).

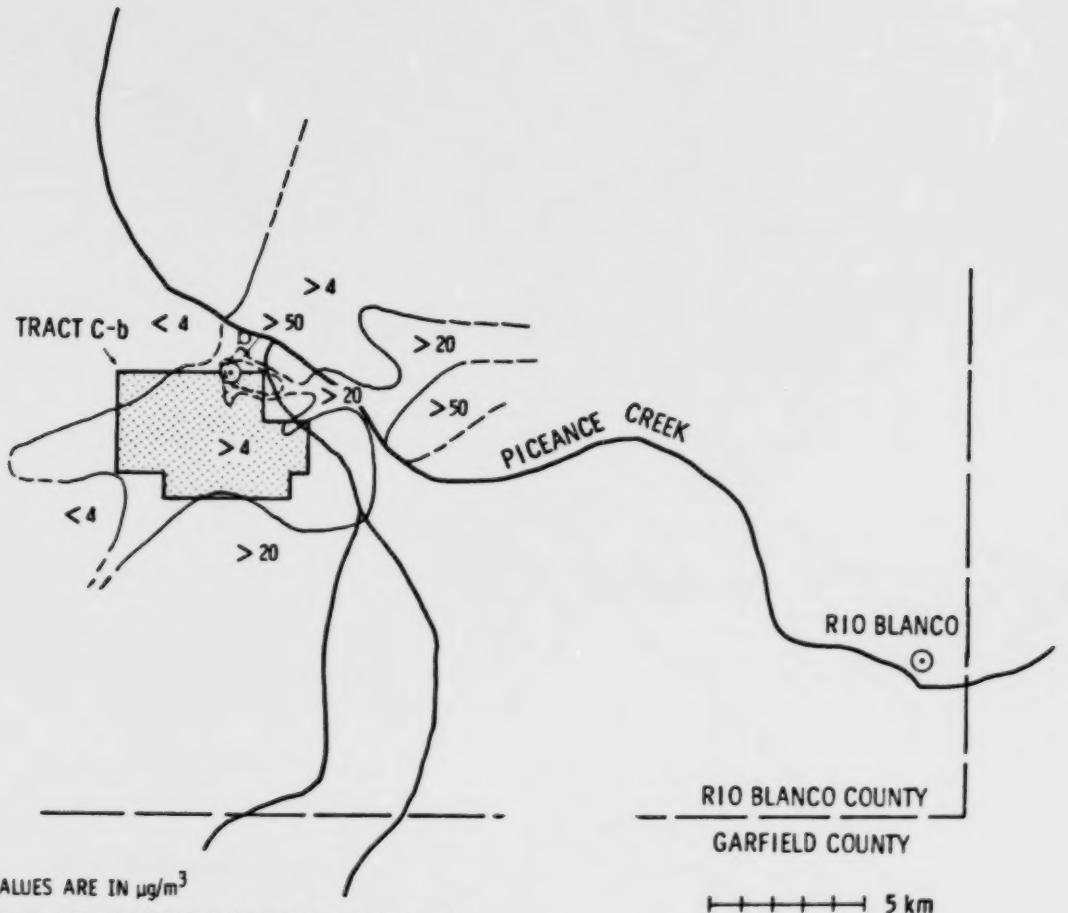
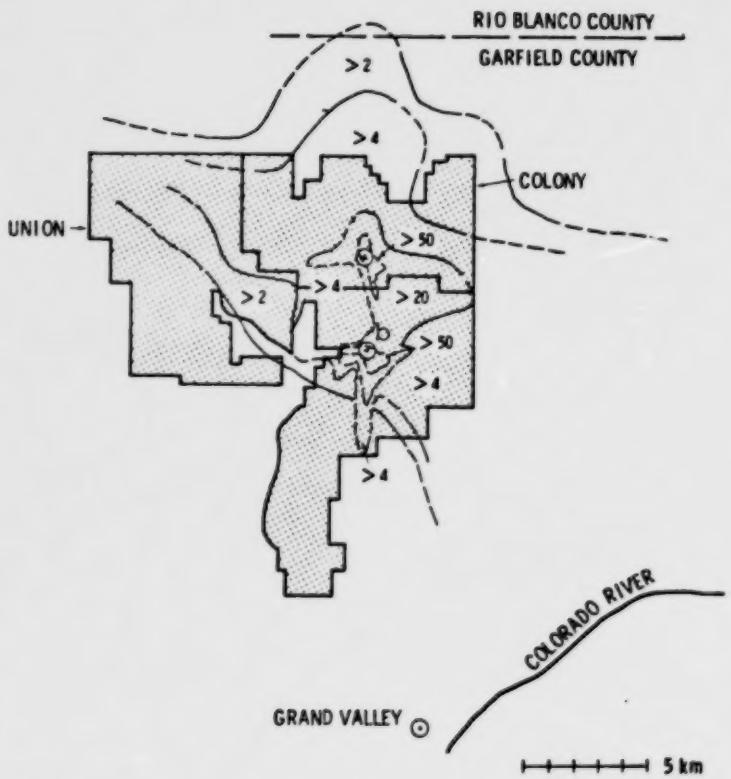



Figure 3. Estimated $NO_x$ ambient concentrations resulting from the Tract C-b (Cathedral Bluffs development).




VALUES ARE IN $\mu g/m^3$

SOLID LINES INDICATE RECEPTOR CONCENTRATIONS

DASHED LINES INDICATE EXPECTED DIRECTION OF ISOPLETH

[b]APPROXIMATE SITING OF NEW PLANT

Figure 4. Estimated $NO_x$ ambient concentrations resulting from the Long Ridge and Colony developments.

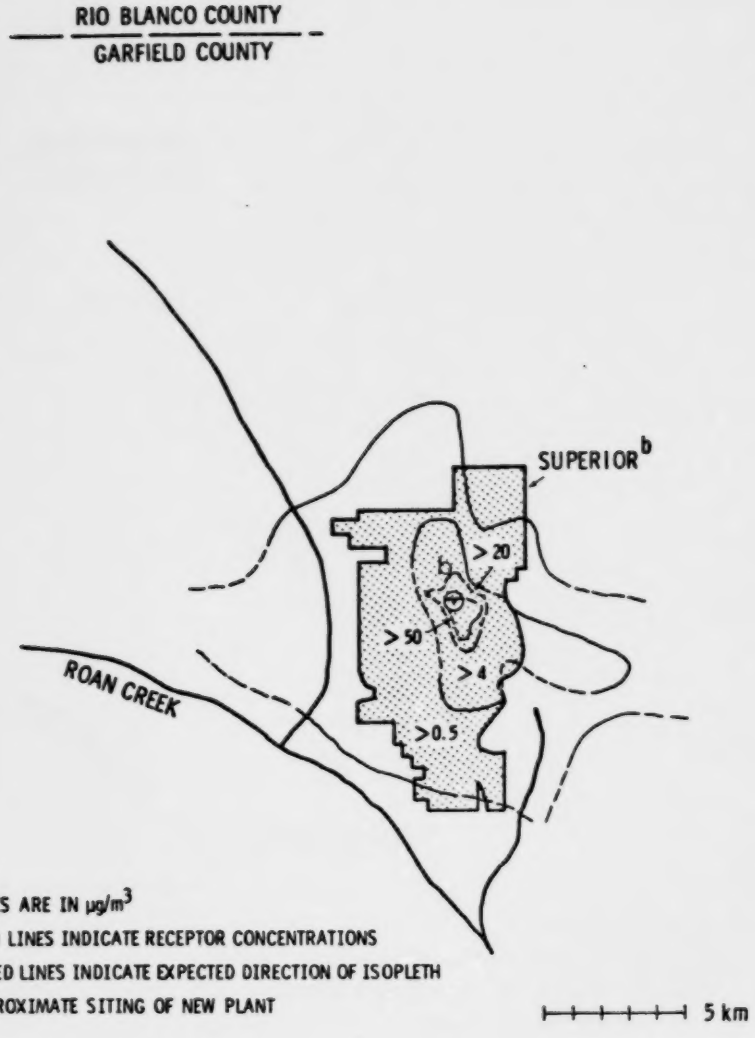



Figure 5. Estimated $NO_x$ ambient concentrations resulting from the Superior Oil Company.

## SECTION 5

## $NO_x/NH_3$ CONTROL TECHNOLOGY SELECTION

The $NO_x$ control was selected by evaluating 17 different control techniques against six primary and three secondary criteria. Tables 9 and 10 list the primary and secondary criteria, respectively.

TABLE 9. PRIMARY SELECTION CRITERIA FOR $NO_x$ CONTROL FROM OIL SHALE RETORT PROCESSES

| |
|---|
| Applicability |
| Status of development |
| Removal efficiency |
| Economics |
| Water usage |
| Industry views |

TABLE 10. SECONDARY SELECTION CRITERIA FOR $NO_x$ CONTROL FROM OIL SHALE RETORT PROCESSES

| |
|---|
| Secondary environmental concentrations |
| Simultaneous removal of other pollutants |
| Data gaps |

PRIMARY CRITERIA

1. Applicability

The selected $NO_x$ control technology should be applicable to the oil shale processing emission streams and should be able to accomodate the effects of sulfur emissions, particulate loading, mositure, ammonia, temperature, corrosivity, and $NO_x$ concentration without deteriorating technology performance. Use of the control technology should preferably be demonstrated on emissions from oil- or gas-fired sources to show the general applicability of the technology on this type of stream.

2. Status of Development

In order to provide proven control technique, the selected $NO_x$ control technology should have been demonstrated on a full-scale, or at least a pilot-scale. Pilot-scale demonstrations should have been reasonably successful under a variety of conditions and show full-scale feasibility. Industrial demonstrations were preferred to utility demonstrations because of the apparent size capability with shale retorting operations. Bench-scale only demonstrations were considered inadequate to warrant selection.

3. Removal Efficiency

Two factors dominate determination of the removal efficiency requirements for a pollution control technology: the level of uncontrolled emissions and the level of emissions permissible for discharge according to the applicable environmental regulations. Adequate information to permit the determination of the required $NO_x$ reduction from the oil shale industry is not available for either of these factors. Nitrogen oxides emission measurements from full-scale oil shale developments are not available and pilot-scale

operation information is insufficient to accurately characterize full-scale industry emissions. Of the applicable environmental standards, the Federal Government has promulgated only the ambient concentration level for $NO_x$ [12]. Standards for a prevention of significant deterioration (PSD) increment currently being studied are not expected to be promulgated for some time [13]. New source performance standards may also apply to some oil shale processes, but have not been specified.

To deal with the above situation and to assure that the $NO_x$ control technology selected for testing can be used to establish the future $NO_x$ control necessary to meet anticipated Government standards, three scenarios were considered. These scenarios, used for technology selection purposes only, are in no way to be construed as an indication of future regulations.

The first scenario represents the current regulatory status and is based on the industry's need to comply with the existing ambient standard of 100 $\mu g/m^3$ (0.05 ppm) of $NO_x$ [11]. This scenario will remain valid until new or additional regulations are promulgated. Technologies that are included in the planned developments will be described.

The second scenario anticipates future regulatory requirements and is based on a PSD increment proportional to the currently promulgated sulfur dioxide and particulate matter increments (the only two pollutants with available standards). The ambient annual average standards for sulfur dioxide and particulate matter, as promulgated by EPA, were compared to the respective annual average PSD increments as shown in Table 11. Both pollutants had an increment that was 25 percent of the ambient annual average standard. Therefore, 25 percent of the nitrogen oxides ambient annual average standard of 100 $\mu g/m^3$ would give an estimated PSD increment of 25 $\mu g/m^3$. It should be noted that while sulfur dioxide and particulate matter are Set I PSD pollutants, $NO_x$ is a Set II

TABLE 11. CURRENT GOVERNMENT ANNUAL STANDARDS FOR SULFUR DIOXIDE AND PARTICULATES [12,13]

| | Ambient[a] | PSD[a] | Percent reduction |
|---|---|---|---|
| Sulfur dioxide | 80 | 20 | 75 |
| Particulates | 75 | 19 | 74.7 |

[a] $\mu g/m^3$.

PSD pollutant. If a significantly different method of establishing PSD increments is used for Set II pollutants, the PSD increment for $NO_x$ may be significantly different from the one assumed in this scenario. If the increment is assumed, removal efficiency required for attainment would be approximately 50 percent according to the previous modeling.

The third scenario is based on strict control, i.e., >90%, of the $NO_x$ emission sources. Such control may be necessary if the sources that emit minor amounts of $NO_x$ remain uncontrolled but become a major contributor when combined. The major sources where strict $NO_x$ control may be required and is economically feasible are preheat stacks, hydrogen furnaces, boilers, recycle gas heater, Lungi flue gas stacks, and flue gas desulfurization stacks.

4. General Economics

If regulations require control, the most economical method that achieves the required control will likely be preferred by the industry. In order to evaluate technologies for economic comparison, capital and operating costs from each technology should be compared. Actual costs of full-scale operation are preferred

due to the accuracy. Estimates of pilot-scale to full-scale development can also be considered adequate.

5. Water Usage

Most oil shale retorting developments are in a semi-arid portion of the country where water supplies are limited. A concern of the EPA and industry is the growth limiting aspect of this lack of water. Most retort operations require large amounts of water for processing the shale, recovering the vaporized oil, and treating the spent shale. Additional water requirements for pollution control may limit the availability of water to these operations and oil production. An $NO_x$ control technology that minimizes the use of water while maintaining a high removal efficiency is preferable.

6. Industry Views

This criteria was considered in selecting an $NO_x$ control technology because of the need for industry cooperation when testing a pilot-scale device. Several conversations were conducted with developers and government personnel during this project to determine the feeling of oil shale developers to $NO_x$ control.[a,b,c] In general, the developers feel that the levels of $NO_x$ are projected to be low and that $NO_x$ controls are not needed. However, as new regulations for $NO_x$ are promulgated, the industry feels that the following factors should be considered in selecting an appropriate technology [14]:

---

[a] Personal communication with Charles Bray, Occidental Oil Shale Company, March 11, 1981.

[b] Personal communication with Roger Tucker, USGS, Area Oil Shale Office, Grand Junction, Colorado, February 27, 1981.

[c] Personal communication with John Hyatt, Exxon Oil Company, March 27, 1981.

(1) There are currently at least six generically different retorting processes under development. As more advanced technologies are developed, there will undoubtedly be more. Since processes differ, a control technology and associated performance standard that might be appropriate for one may be totally inappropriate for another. This fundamental fact must be recognized when performance standards are set.

(2) The control technologies being proposed for use on oil shale processes are technologies that have been developed in other industries. There is a high probability that these technologies will also work when applied to oil shale processes. However, the removal efficiencies that can reasonably be expected of these technologies when applied to oil shale have not been demonstrated. Until these demonstrations are made, it would be inappropriate to set removal efficiencies as performance standards.

(3) Performance standards that have been developed in other industries have been based on well run plants operating under commercial conditions. No such experience exists in the shale industry.

Because of the current industry opinion on $NO_x$ control, this criteria was dropped from the selection process. However, the industry concern over selection, particularly the enumerated points were considered.

SECONDARY CRITERIA

1. Secondary Environmental Considerations

A selected control technology should not generate secondary pollutants. Technologies that generate sludges, wastewater, dusts, or various air pollutants are less preferable than those that generate no secondary waste streams.

2. Simultaneous Removal of Other Pollutants

One desirable characteristic that is often available with $NO_x$ control technologies is the simultaneous removal of other pollutants. This is desirable because it would reduce the cost of air pollution control.

3. Data Gaps

The selected technology should have all necessary design criteria, tested operations, demonstrated efficiency, and problem descriptions. This information should available. Technologies that require negotiations for designs or trade secrets should have controlling parties that indicate a willingness to cooperate with this project.

The above criteria were applied to each technology to identify the best technology to control $NO_x$ emissions from oil shale developments. The criteria were applied according to their priority, listed in order in Tables 9 and 10. The first scenario presented in the removal efficiency description did not require any application of the criteria because it required no further control. Scenario two applied the criteria on an individual oil shale process basis, e.g., to each type of process (gas turbines, preheat systems, etc.). Since most combustion modifications are only applicable to certain types of processes and no modification can sufficiently reduce $NO_x$ concentrations for all emission sources. The third scenario applied the criteria to all controllable sources at one time to select one technology capable of controlling $NO_x$ emissions from the major sources.

Applicability evaluations for the second scenario identified combustion modification techniques that could be individually applied to preheat systems, steam generators, gas turbines and related processes. If a modification was applicable to several

of these, it was evaluated individually for each. If a modification was not applicable to any of these operations, it was eliminated from further consideration. The remaining modifications were then evaluated for present development status. Modifications currently being tested on pilot-scale units were not considered. Those available and tested on full scale equipment were preferred but technologies not demonstrated yet showing good potential for other criteria were considered. Based on the scenario required, removal efficiency was 40-50 percent. Those modifications that were controlled less were not considered. Relative economics was then considered. Modifications that cost a factor of two more than the median for combustion modification techniques were eliminated. Water usage final decision criteria was used to separate those technologies that used water from those that do not. Secondary criteria were not considered for the second scenario.

The third scenario used applicability to determine if the technologies could potentially control the $NO_x$ major sources at the developments. Development status was applied to those technologies demonstrating applicability. Full-scale development of the flue gas treatment technology was preferred. Pilot-scale developments were considered if the technology had potential in other criteria areas and was near full-scale development based on the size and number of pilot-scale units. Technologies with minor pilot-scale tests and bench-scale technologies were not considered further. For the remaining technologies that could not attain that removal efficiency of 40-50 percent were eliminated. Relative economics between technologies was then evaluated. Those technologies that were less than two times the median cost were evaluated for water usage. Technologies with little or no water requirements were preferred over those using water. Secondary criteria were not applied for this scenario because a single selection had been made.

The current NAAQS requires that the annual average $NO_x$ concentration not exceed 100 $\mu g/m^3$. This standard pertains to all public access areas but excludes privately controlled areas such as plant sites [12]. The results of the modeling performed on the five planned oil shale facilities show that the current standard would not be exceeded (Section 4). Therefore, no control would be necessary for $NO_x$ emissions. This modeling was based on estimated $NO_x$ emissions that assumed ammonia recovery would be used on most gas streams. Many of the developers are currently planning on recovering or reducing the concentration of ammonia from the retort product gas [15]. In Table 12, average composition and the actual volumetric flow rates of retort off-gas is listed for six processes. As shown in the table, ammonia concentration is generally below 1% (dry volume basis). The Lurgi process is reported to generate negligible amounts of ammonia. No information was found on ammonia concentrations from the TOSCO II process even though the Colony Oil Company is intending to recover ammonia. Even at these low concentrations, the ammonia concentration is a factor of 10 higher than the nitrogen oxides concentration. If this ammonia was oxidized and released into the atmosphere, the developments would potentially exceed the NAAQS.

Theoretically, ammonia can be easily decomposed or oxidized at elevated temperature as shown in the following equations:

$$NH_3 \rightleftarrows 1/2\ N_2 + 3/2\ H_2$$

$$2NH_3 + 5/2\ O_2 \rightleftarrows 2NO + 3H_2O$$

$$2NH_3 + 7/2\ O_2 \rightleftarrows 2NO_2 + 3H_2O$$

If oxygen was not present, 90 percent of the ammonia would decompose to nitrogen and hydrogen at a temperature of approximately 254°C. However, with the presence of oxygen, the decomposition

TABLE 12. AVERAGE COMPOSITION AND VOLUMETRIC FLOW RATE OF RETORT OFF-GAS

| Component | Paraho Direct heating [14-16], volume % | Paraho Indirect heating [14], volume % | Lurgi [14-16], volume % | Oxy-MIS [14-16], volume % | TOSCO II [16], volume % | Union B [16], volume % |
|---|---|---|---|---|---|---|
| $N_2$ | 64.6 | 0.7 | 3.9 | 56.6 | - | 0.1 |
| $CO_2$ | 23.0 | 15.1 | 30.8 | 29.9 | 19.5 | 18.4 |
| CO | 2.2 | 2.6 | 4.1 | 1.0 | 3.3 | 5.0 |
| $H_2$ | 3.4 | 24.8 | 18.6 | 5.4 | 19.5 | 24.2 |
| $CH_4$ | 2.3 | 28.7 | 14.5 | 1.6 | 19.4 | 23.1 |
| $C_2$'s | 1.6 | 15.9 | 10.1 | 0.4 | 15.3 | 9.9 |
| $C_3$'s | 0.8 | 5.5 | 6.4 | 0.2 | 10.1 | 7.3 |
| $C_4$'s | 0.4 | 2.0 | 8.7 | 0.2 | 5.1 | 4.1 |
| $C_5^+$ | 0.5 | - | 1.3 | 0.2 | 4.0 | 3.8 |
| $O_2$ | 0.5 | - | - | 0.1 | - | - |
| $NH_3$ | 0.5 | 1.2 | - | 0.4 | - | 0.2 |
| $NO_x$ | - | - | - | - | - | - |
| $H_2S$ | 0.3 | 3.5 | 1.9 | 0.2 | 3.9 | 3.9 |
| $SO_2$ | - | - | (0.06 g/NM$^3$) | - | - | - |
| $CS_2$ | - | - | - | - | - | - |
| RSH | - | - | - | - | - | - |
| COS | - | - | - | - | - | - |
| $H_2O$ | - | - | - | 3.8 | - | - |
| Actual volumetric flow rate[b], m$^3$/s | 287 | - | 10.0 | 611 | 647 | 245 |

[a]Average of data from References 14 and 16.

[b]Data are calculated from gas rate (lb/hr) in Reference 16 by assuming ideal gas state.

of ammonia would occur mostly through the mechanisms of the latter two reactions [17]. If all the ammonia in the retort off-gas is assumed to be converted to $NO_2$, the worst-case emission rate of $NO_x$ can then be calculated as shown in Table 13. If this large release of $NO_x$ occurred continuously during retort operations, the NAAQS would be exceeded. Ammonia can be removed from the retort gas by absorption in water, or reaction with an acid solution, usually in conjunction with a gas cooling/conditioning step [15]. Table 14 lists the developments that are currently planning to recover ammonia. Removal of ammonia from the off-gas oil shale retort not only helps control emissions of $NO_x$, but can also recover by-product ammonia, an important industrial chemical, in the form of liquid ammonia and/or ammonium sulfate.

No specific information on ammonia recovery/removal efficiency from these developments is available due to the current planning stages of the developments. But, the capture and recovery of ammonia is a proven process. In the case of oil shale retort off-gas, the off-gas composition is similar to coal gas. Typical concentration of ammonia in coal gases (about 1.1 volume percent) is very close to that of oil shale off-gas (about 1.0 volume percent [20]). Ammonia separation from coal gas production has been practiced and has changed very little for over 50 years; in fact, a modern installation is hardly distinguishable from a plant constructed many years ago [18, 19]. The basic principles underlying processes used for coal-gas purification are directly applicable to ammonia removal from gases produced in shale retorting. Nearly all processes in commercial use are based on washing the gas stream either with water or with a strong acid and removing the ammonia either in the form of aqueous solutions of ammonium hydroxide or as the salt of the acid used as the absorbent. There are two commonly used commercial processes for removing ammonia from coal gases, namely, indirect and semidirect [18].

TABLE 13. ESTIMATED AMMONIA RECOVERY FROM RETORT OFF-GAS AT FULL-SCALE OPERATIONS

| | Paraho | | | |
|---|---|---|---|---|
| | Direct heat | Indirect heat | Oxy-MIS | Union B |
| Actual volumetric flow rate, $m^3/s$ | 287 | -[a] | 611 | 245 |
| $NH_3$ volume, % | 0.5 | 1.2 | 0.4 | 0.2 |
| $NH_3$ concentration, $g/m^3$ | 3.8 | - | 3.0 | 1.5 |
| $NO_2$ concentration, $g/m^3$[b] | 10.2 | - | 8.2 | 4.1 |
| $NO_2$ concentration, kg/hr | 10,600 | | 18,100 | 3,630 |
| $NH_3$ recovery, % | 95 | - | 98 | 95 |
| $NH_3$ recovery, $g/m^3$ | 0.21 | - | 0.16 | 0.082 |

[a]Flow rate is not reported.

[b]Assumes complete oxidation.

TABLE 14. DEVELOPMENTS THAT PLAN TO RECOVER AMMONIA [15]

| |
|---|
| Cathedral Bluffs Shale Oil Company (MIS process) |
| Long Ridge Experimental Shale Oil Project |
| Colony Development Operation |
| Rio Blanco Oil Shale Company |
| White River Shale Project |

These processes are described in Appendix B. When one of these processes is used with a packed tower scrubber and a saturator, a 98 to 99 percent removal efficiency can be attained[a]. The resulting effect of the removal of 98 percent of the ammonia from the retort off-gas is presented in Table 13. Thus, ammonia

[a]Personal communication with Norman Mansson, Regional Sales Manager, Koch Engineering, New York Division, 19 June 1981.

recovery is environmentally beneficial through a large reduction in $NO_x$ potential, and also offers an economic incentive.

## SCENARIO TWO - COMBUSTION MODIFICATION

Scenario two calls for moderate control (~50%) of $NO_x$ from oil shale combustion processes. Combustion modification techniques can achieve this amount of control at a much lower cost than add-on devices because of lower capital and operating costs, lower maintenance requirements, and potentially higher reliability due to fewer down times and no dependence on external operations. The principles of combustion modification and the selection of specific techniques for specific process application are discussed in the following sections.

### Principles of Control

Oxides of nitrogen ($NO_x$) formed in combustion processes are typically due either to thermal fixation of atmospheric nitrogen in the combustion air, leading to "thermal $NO_x$" or to the conversion of chemically bound nitrogen in the fuel, leading to "fuel $NO_x$." There is an increased potential for fuel $NO_x$ formation in oil-shale-associated combustion processes because of the nitrogen content of shale-derived fuels. Crude shale oil that is expected to be used to generate energy at the site, contains 1-2% nitrogen [21]; a typical fuel oil contains approximately 0.3% nitrogen [22]. The product gas will contain some amount of ammonia, even after gas conditioning (approximately 60-100 ppm assuming 98% removal of ammonia) while natural gas contains negligible amounts of nitrogen. Both thermal and fuel $NO_x$ appear to be kinetically or thermodynamically limited because emission rates are far below the levels which would prevail at equilibrium. Thus, the rate of formation of both thermal and fuel $NO_x$ is dominated by combustion conditions and is amenable to suppression through combustion process modifications [22].

Although the formation mechanisms are different, the production of both thermal and fuel $NO_x$ is promoted by rapid mixing of oxygen with the fuel. Additionally, thermal $NO_x$ is greatly increased by long residence times at high temperature [1]. Thus, $NO_x$ levels can be reduced by modifying the combustion conditions in order to limit the availability of oxygen near the flame and/or limiting the time of exposure at high temperature. The various combustion modification control strategies are based on one or both of these concepts.

## Combustion Modification Techniques for Oil Shale Application

The combustion modification controls reviewed for possible application to the major sources of $NO_x$ at oil shale developments include:

- Low excess air
- Staged combustion
- Low $NO_x$ burners
- Flue gas recirculation
- Water injection
- Reduced combustion air preheat

Table 15 briefly describes the control concept, the effect of control on the two types of $NO_x$, and what type of action is required for these modifications. Table 16 compares these technologies to the selection criteria described earlier.

Combustion modification to limit the amount of excess air can be applied to steam generators, preheat systems, and gas turbines which make up the major $NO_x$ combustion sources. This type of modification is practiced in commercial operations and has a demonstrated effectiveness in reducing $NO_x$. Low excess air provides only a small amount of control, averaging 11 percent [22]. However, it

TABLE 15. CHARACTERISTICS OF COMBUSTION MODIFICATION TECHNIQUES

| Combustion modification technique | Control concept | Effect on thermal $NO_x$ | Effect on fuel $NO_x$ | Action required |
|---|---|---|---|---|
| Low excess air | Decrease overall $O_2$ level | Reduces $O_2$ rich, high $NO_x$ pockets in the flame | Reduces exposure of fuel nitrogen intermediaries to $O_2$ | Operational adjustment |
| Staged combustion | Primary fuel rich flame zone | Flame cooling in low $O_2$, low temperature primary flame zone reduces peak temperature | Volatile fuel N reduces to $N_2$ in the absence of oxygen | Hardware modification |
| Low $NO_x$ burners | Delayed mixing of fuel and air | Flame cooling and dilution during delayed mixing reduces peak flame temperature | Volatile fuel N reduces to $N_2$ in the absence of oxygen | Hardware modification |
| Flue gas recirculation | Decrease adiabatic flame temperature | Direct suppression of thermal $NO_x$ mechanism | Ineffective | Hardware modification |
| Water injection | Decrease adiabatic flame temperature | Direct suppression of thermal $NO_x$ mechanism | Ineffective | Hardware modification |
| Reduced combustion air preheat | Decrease adiabatic flame temperature | Direct suppression of thermal $NO_x$ mechanism | Ineffective | Operational adjustment |

[a] For oil-fired boilers.

[b] For gas-fired boilers.

## TABLE 16. EVALUATION OF COMBUSTION MODIFICATIONS FOR $NO_x$ CONTROL

| $NO_x$ control technologies | Applicability to oil shale retorting operations | Status of development | Removal efficiency, % | General economics | Use of water | Scenario rating |
|---|---|---|---|---|---|---|
| Low excess air | Applicable to preheat systems, steam generators, and gas turbines | Currently available | 0-28<br>11 average | Operating cost: 20 mills/GJ input | None | Fair |
| Staged combustion | Applicable to preheat systems, and steam generators | Currently available | 20-50<br>(2 stages) | Operating cost: 36 mills/GJ input | None | Good |
| Low $NO_x$ burners | Applicable to preheat system, and steam generators | Available but not demonstrated | 20-50 | Operating cost: 56 mills/GJ input | None | Good |
| Flue gas recirculation | Applicable to steam generators | Available for retrofit | 15-30 | Operating cost: 75 mills/GJ input | None | Poor |
| Water injection [23] | Applicable to gas turbines | Currently available | 15-40 | Fixed cost: $1,700/GJ/hr | Water:fuel = 0.5-1:1 | Good |
| Reduced combustion air preheat | Applicable to all processes except Lurgi process | Currently available | 5-16 | Operating cost: 42 mills/GJ input | None | Fair |

is also the least expensive to operate and can readily be supplemented by (of supplement) other combustion modification techniques. As a single modification, it is rated fair due to the minimal control.

Staged combustion and low $NO_x$ burners operate on essentially the same concept for $NO_x$ abatement. Staged combustion involves burning the fuel with a sub-stoichiometric (70-90%) amount of combustion air in the primary flame zone, and then injecting secondary air to complete combustion at some distance farther along the combustion chamber. In the absence of oxygen the fuel bound nitrogen is reduced to $N_2$ instead of being oxidized to $NO_x$. Low $NO_x$ burners operate on the same principle, but secondary air is introduced through the burner. The geometry of the burner delays mixing of the secondary air with the combustion products from the primary flame zone, resulting in effective staged combustion.

Staged combustion can be used to control $NO_x$ emissions from steam generators and preheat systems but is ineffective for gas turbines. This modification is capable of moderate removal (20-50 percent) and is also an inexpensive modification to operate. This process can also be coupled with other technologies for slightly higher removal. This modification is a good selection for the applicable process under this scenario.

Low $NO_x$ burners are applicable to preheat systems and steam generators. This modification is available for use but has not been fully demonstrated. Capable by itself of reducing $NO_x$ up to 50 percent alone, this modification can be combined with other modifications for improved removal. Cost for this modification is approximately 50 percent higher than for staged combustion. The scenario rating for this modification is good based on its good removal and applicability but is second choice to staged combustion for the applicable processes because of its higher cost.

Flue gas recirculation can be applied to steam generators and is currently available for retrofitting onto a process. However, the process is only capable of reducing $NO_x$ by 15-30 percent and has a large operating cost compared to other modifications. These reasons limit this method to a poor rating.

Unlike other modifications, water injection is applicable to gas turbines but is ineffective for other oil shale related processes. This currently available technology can remove 15-40 percent depending on operating conditions. Operating cost is unknown but is expected to be slightly higher than other modifications. The process uses a ratio of approximately 0.5:1 water to fuel [23] to reduce the burner temperature and thus control $NO_x$. The water used for this control is lost from the process and cannot be recycled which may reduce this technology application in this industry. The scenario rating for this modification is good but is limited to gas turbines.

The last combustion modification technique considered for application to retorting processes was reduced combustion air preheat. This process is applicable to all processes except Lurgi and is currently being used for commercial and utility boilers. This modification is limited to 16 percent removal and has a moderate operating cost making only a fair choice for $NO_x$ reduction. Control of $NO_x$ by combustion modification can be an effective and economical practice.

Combustion modifications can reduce the $NO_x$ emissions by up to 50 percent. Combination of these technologies (not considered here) can increase removal efficiency and improve a modification that has a fair rating to a good rating. The combustion modifications that have been selected for controlling $NO_x$ from retorting processes are presented in Table 17.

TABLE 17. SELECTED COMBUSTION MODIFICATION TECHNIQUES

| Source | Combustion modification technique |
|---|---|
| Preheat systems | Low excess air and staged combustion or low $NO_x$ burners |
| Steam generators | Low excess air and staged combustion or low $NO_x$ burners |
| Gas turbines | Low excess air and water injection |
| Lurgi flue gas stacks | Not applicable |

The Lurgi process does not lend itself to combustion modification control techniques because of the unconventional nature of the process. The residual carbon left in the retorted shale is burned as the shale is transported up a lift pipe by hot combustion air. Modifications may adversely affect this lifting process and alter the heat recovery process that has been developed by Lurgi.

SCENARIO THREE - FLUE GAS TREATMENT TECHNOLOGY

If federal regulations require more stringent control of $NO_x$, as postulated in the third scenario, or combustion modification techniques are not applicable to the major emission sources, flue gas treatment (FGT) is necessary. Flue gas treatment can be divided into two types; technologies that selectively control $NO_x$ and those that control $NO_x$ and sulfur dioxides ($SO_x$) simultaneously. These two types contain 11 major technologies that are currently being used or tested. Table 18 presents these major $NO_x$ control technologies.

By comparing the two types of control, some general conclusions can be reached. Both control types have good potential application to oil shale processes with the major problem being the need for particulate control prior to some technologies. Control

TABLE 18. MAJOR FLUE GAS TREATMENT TECHNOLOGIES [20]

| |
|---|
| $NO_x$ removal only |
| Selective catalytic reduction - fixed bed reactor |
| Selective catalytic reduction - moving bed reactor |
| Selective catalytic reduction - parallel flow reactor |
| Absorption - oxidation |
| Selective noncatalytic reduction |
| $NO_x/SO_x$ simultaneous removal |
| Selective catalytic reduction - parallel flow reactor |
| Adsorption |
| Electron beam radiation |
| Absorption - reduction |
| Oxidation - absorption - reduction |
| Oxidation - absorption |

technologies for $NO_x$ only are generally well developed, while those with simultaneous $NO_x/SO_x$ control are still in the prototype or pilot stages. The one exception is a proven technology that is also used for selective $NO_x$ control. $NO_x$ removal efficiencies are generally lower for the simultaneous removal technologies with the exception of the two least developed and the one fully developed technologies. Economically, the $NO_x$-only technologies are less expensive. However, this does not take into account any possible savings by eliminating the need for a $SO_x$ control process. Water is not used for most of the $NO_x$-only technologies but may be a limiting factor on several of the simultaneous $NO_x/SO_x$ technologies. In general, the $NO_x$-only technologies are more attractive than the simultaneous $NO_x/SO_x$ technologies based on the selection criteria.

Brief descriptions of the 11 major technologies are presented below. These descriptions include major features of the technologies and discuss the application of the selection criteria to the technologies.

## Selective Catalytic Reduction

One of the most efficient technologies for controlling $NO_x$ emissions is selective catalytic reduction (SCR). SCR is based on the catalyzed reaction between $NO_x$ and ammonia to form nitrogen and water. The use of a catalyst reduces the required temperature range for $NO_x$ reduction from 950-1000°C to 150-450°C [1]. The catalyst also improves the reliability and removal efficiency. Base metals are generally used as the catalyst. Alumina was the original carrier for the catalyst but, due to the sulfur dioxide ($SO_x$) poisoning, was replaced by a titanium oxide based, $SO_x$ resistant catalyst. A major problem with SCR is the potentially severe plugging of the catalyst and the beds from dirty, particulate-laden gas. As a result, three reactor configurations capable of handling varying particle concentrations have been developed and are currently in use in Japan. Each configuration can handle different levels of particulate loading and are evaluated separately below.

## Selective Catalytic Reduction-Fixed Packed Bed Reactors [2]

Fixed packed bed systems are applicable only to flue gas streams containing less than 20 $mg/Nm^3$ of particulates. The primary feature of these systems is the reactor which contains the catalyst. As the name implies, the granular catalyst is randomly packed in a stationary bed. The catalyst can be either spherical or cylindrical in shape. Spherical granules typically range in size from 4-10 mm in diameter. The composition varies from process to process and most formulations are proprietary. Catalysts available today for use in treating flue gas containing $SO_2$ and $SO_3$ are generally resistant to poisoning by these compounds. Long-term tests of these catalysts in the presence of $SO_x$ have shown very little or no decrease in activity or selectivity. The catalyst is supported either by inert packing or by a perforated support plate.

Fixed bed reactors have potential applicability to retorting operations only if a particulate control device is placed prior to the reactor. Severe plugging of the reactor can result from a gas stream that contains particulate matter rendering the reactor ineffective. Fixed bed reactors are currently used at eight commercial operations in Japan and several have been pilot tested in the United States. These reactors are capable of removing over 90 percent of the $NO_x$ in a gas stream. Economically, the reactor would require a capital cost of approximately $19,400/GJ/hr and about 530 mills/GJ for operating costs. The reactor uses about 1.2 percent of the equivalent boiler energy and has a large pressure drop. Water use is limited to clean-up and deplugging operations. This type of SCR reactor has been rated fair based on its limited applicability but good potential removal, availability, and moderate cost.

Selective Catalytic Reduction-Moving Bed Reactor [2]

In this case, the reactor is a moving-bed type in which a portion of the catalyst is either continuously or intermittently removed from service in order to remove the accumulated particulates. The actual reactor arrangement is highly process specific, however, the principle of operation is the same for all of the processes.

For moderate particulate loadings, the bed is moved intermittently and operated as a fixed bed system most of the time. High particulate loadings require that the bed be moved continuously. Moving bed reactors are reportedly capable of handling up to 2 $g/Nm^3$ of particulates. However, this is more a theoretical than a practical particulate load limit. Entrained particulate matter is generally removed from the catalyst bed by vibrating the bed and screening the catalyst or some other mechanical means. Particulate removal by the bed can be as high as 70 percent.

An example flow diagram for a moving bed SCR process is shown in Figure 6. Flue gas is taken from the boiler between the boiler and the air preheater. An economizer bypass is utilized for temperature control. Ammonia is injected and mixed with the flue gas stream just prior to the reactor. The flue gas passes through the catalyst bed where $NO_x$ is reduced to $N_2$ and is then sent to the stack or further treatment facilities. The catalyst circulates through the reactor is screened to remove particulates. The particulates are blown to a small baghouse for collection.

Moving bed reactors have potentially good applicability to oil shale retorting operations. The limiting factor is the particulate loading but this does not appear to be a significant problem. Particulate loading in off-gas emissions are predicted to be approximately 35-37 $mg/Nm^3$ [24], well below the moving bed reactor limit of 2 $g/Nm^3$. Moving bed reactors are currently being used at six Japanese commercial oil-fired boilers. This type of reactor is capable of removing over 90 percent of the $NO_x$ in an emission stream. Costs are comparable to a fixed bed reactor with a slightly lower operating cost (500 compared to 530 mills/GJ), a reduction in required energy (1% compared to 1.2%), and a lower pressure drop. Water usage is minimal being used only for clean up and emergency deplugging operations. This $NO_x$ control technology is rated as having good potential based on its applicability, availability, removal efficiency, and its moderate cost.

Selective Catalytic Reduction-Parallel Flow Reactor [2]

The distinguishing aspect of this process is the catalyst shape which is produced in a variety of shapes. The catalysts are produced in either a honeycomb, pipe, or plate shape. Both metal and ceramic supports are employed. Several shapes are illustrated in Figure 7. The catalyst shapes allow particulate-laden flue gas to pass through the reactor with no inertial impaction of the

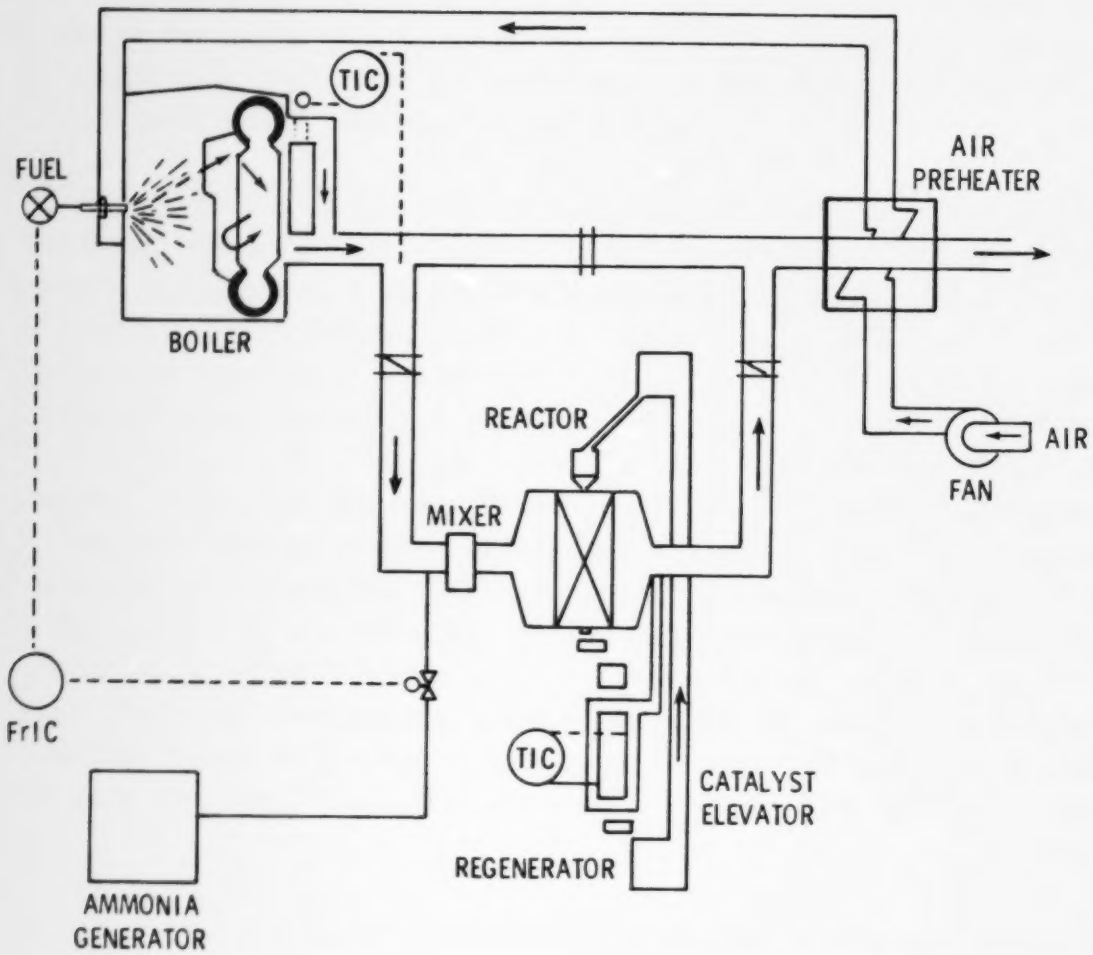



Figure 6. Process flow diagram for moving bed SCR process [2].

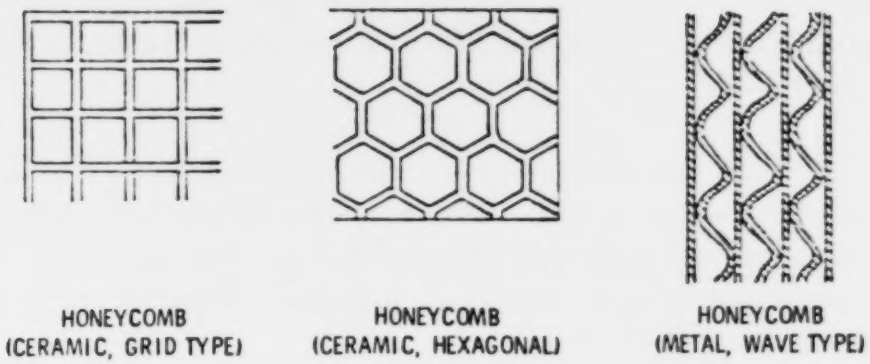



Figure 7. Shapes of parallel flow catalysts [2].

particles while the $NO_x$ is transported to the catalyst surfaces by basic diffusion. The catalysts can handle up to 20 $g/Nm^3$ [1] particulate levels.

The reactors used are similar to standard fixed bed units and an example is shown in Figure 8. The catalyst is usually prepared in small modules and manually stacked within the reactor. The specific arrangement will depend on the particular process under consideration.

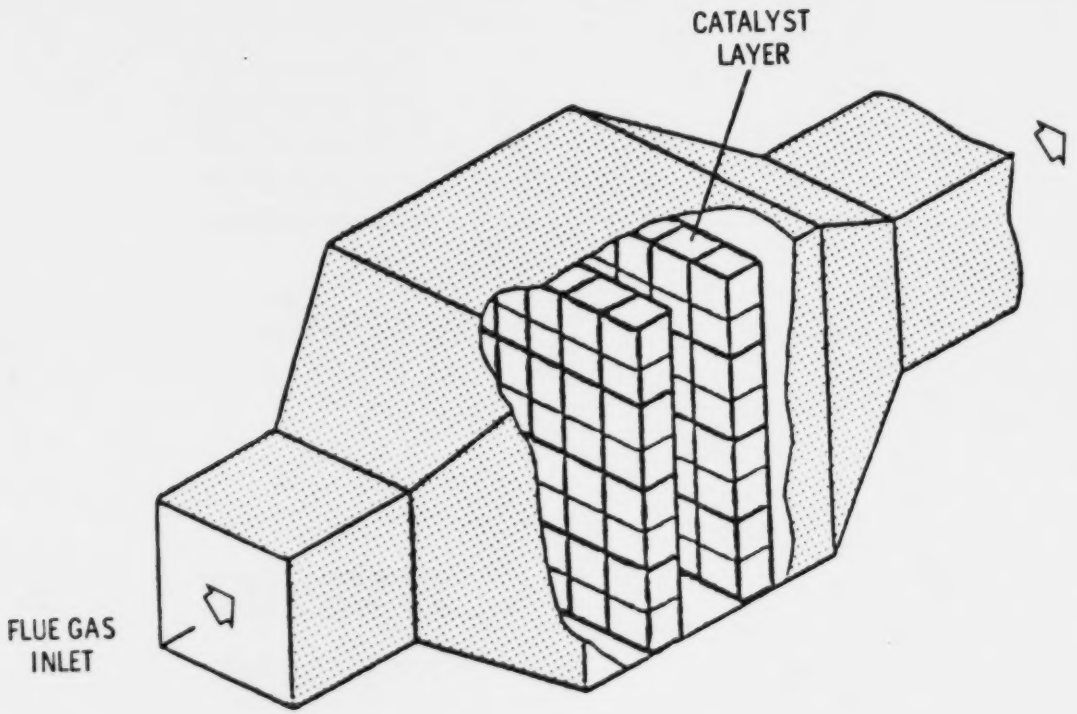



Figure 8. Typical reactor used with parallel flow SCR process [2].

A typical flow diagram for a parallel flow SCR system is shown in Figure 9. The arrangement is similar to the other SCR processes in that hot flue gas leaving the boiler economizer is injected with $NH_3$ and passed through a catalyst bed. Temperature control is important and can be accomplished with either a fired heater or an economizer bypass. $NH_3$ can be controlled using boiler operating condition inputs to conventional control components.

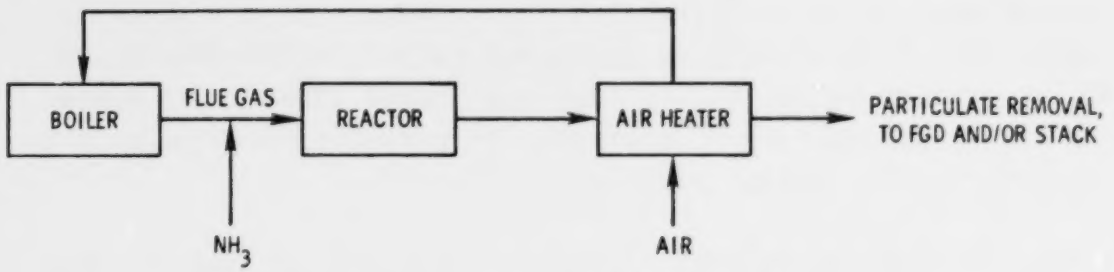



Figure 9. Flow diagram for parallel flow SCR process [2].

Parallel flow reactors are capable of handling all of the particulate levels emitted by standard boilers and thus, possess good applicability to particulate-laden retorting processes. Plugging of the reactor is an infrequent occurrence unlike the fixed or moving bed reactors which can plug ofter under large particulate loadings. Parallel flow reactors capable of handling over 10,000 $Nm^3/hr$ are currently used at 15 locations in Japan [1] and have been tested in the United States. Several Japanese companies have designated licenses in the United States to market their systems. Parallel flow reactors are capable of removing over 90 percent of the $NO_x$ in a gas stream. This reactor design is less expensive to purchase and operate than the other reactors requiring a capital cost of approximately $10,800/GJ/hr and an operating cost of $420 mills/GJ [20]. Water requirements are minimal. This type of $NO_x$ control is considered to be a good potential treatment

technology for use in controlling $NO_x$ emissions from oil shale retorts due to its applicability, status of development, removal efficiency and moderate cost.

Absorption-Oxidation [2]

Absorption-oxidation processes remove $NO_x$ from flue gas by absorbing the NO or $NO_2$ into a solution containing an oxidant which converts the $NO_x$ to a nitrate salt. Two types of gas/liquid contractors can be used and examples of each type are shown in Figure 10. Both perforated plate and packed towers accomplish $NO_x$ absorption by generating high gas/liquid interfacial areas. The choice of one type of contactor is a design decision made to achieve a given removal for the least cost.

Before the gas can be sent to the $NO_x$ absorber, it must be $SO_2$-free since $SO_2$ consumes prohibitive amounts of the costly liquid-phase oxidant. In most cases, the oxidant is permanganate ($MnO_4^-$); however, $Ca(ClO)_2$ can also be used. Therefore, a conventional FGD unit is required ahead of the $NO_x$ absorber. A prescrubber to cool the gas and remove both particulates and $Cl^-$ prior to FGD is also necessary. After having passed through these two scrubbing sections, the flue gas enters the distributing space at the bottom of the $NO_x$ absorber, below the packing or plates. The gas passes upward through the column, countercurrent to the flow of the liquid absorbent/oxidant (usually a KOH solution containing $KMnO_4$). Nitrogen oxide is absorbed and then oxidized over the length of the column.

The clean gas passes out of the top of the absorber to a heater for plume buoyancy and is sent to the stack. The absorbing solution drops to a holding tank where makeup KOH and/or $KMnO_4$ are added. This solution flows to a centrifuge to separate the solid $MnO_2$ which is then electrolytically oxidized to $MnO_4$. The remaining solution is either concentrated in an evaporator to

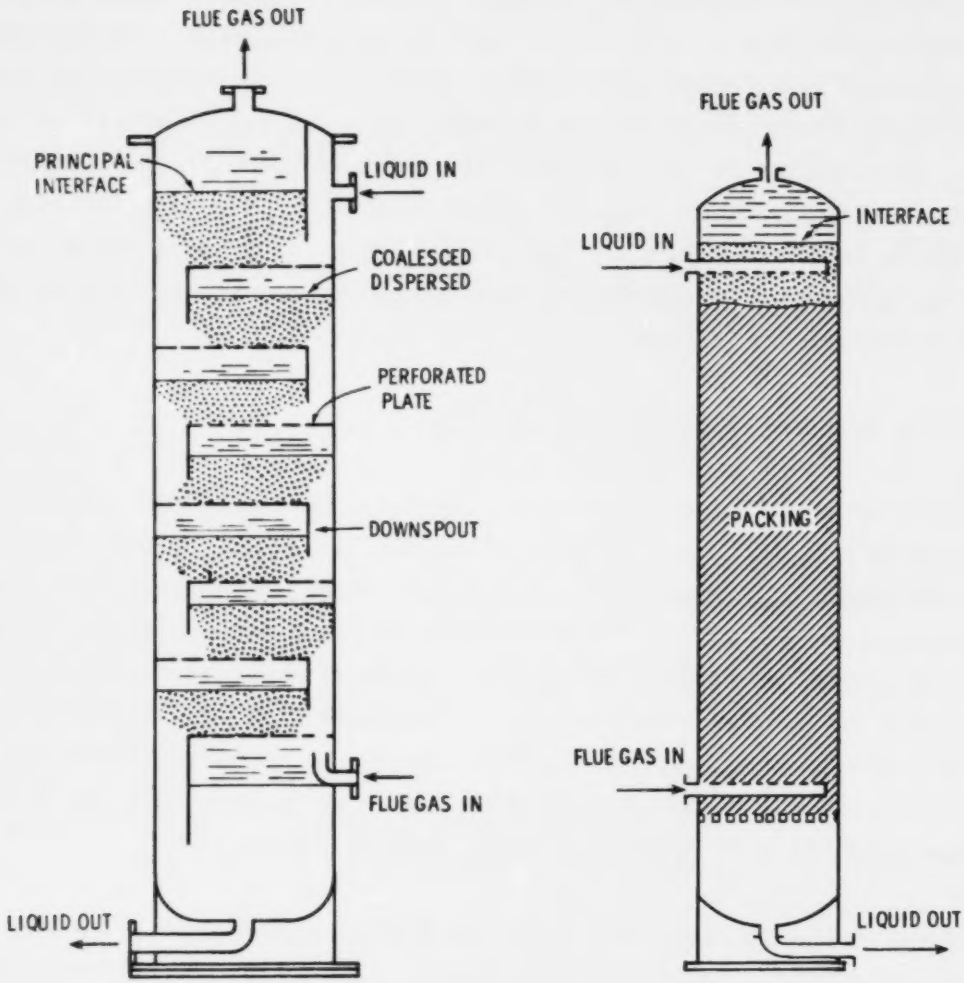



Figure 10. Gas/liquid contactor options for wet $NO_x$ processes [2].

form a weak $KNO_3$ solution or is electrochemically treated to produce a weak $HNO_3$ solution and a mixed stream of KOH and $KNO_3$.

Because of the number of gas pretreatment steps necessary prior to an absorption-oxidation process, this technology does not have good applicability to oil shale retorting processes. Development has not progressed past the pilot-scale or small commercial scale. Removal efficiencies of 85-95 percent have been reported for these units. Economics of the process are unknown but it is estimated that such a unit would require approximately 3 percent of the equivalent boiler output. The limitations of this process to adapt to retorting processes and the unknown economics make this control technology a poor choice for this industry.

SELECTIVE NONCATALYTIC REDUCTION [1]

Selective noncatalytic reduction (SNR) is the simplest method for removing $NO_x$ from flue gas and is useful in removing $NO_x$ up to about 50 percent. Ammonia is injected into a flue gas that has a temperature above 600°C. The ammonia reacts with the $NO_x$ in the gas to produce nitrogen and water. Removal efficiencies up to 80 percent have been reported in laboratory tests but required considerable excess ammonia resulting in large blowover concentrations. Normal removal is less expensive and useful for gas streams that do not require a high removal ratio.

SNR is potentially applicable to retorting processes. Large amounts of ammonia would be required. The necessary ammonia may be available from the ammonia removal processes. Considerable preheating is also necessary since most retort off-gases are cooler than 600°C. This process is used in Japan for emergency control of $NO_x$ emissions. The 40-60 percent removal percentage is considerably below the SCR or absorption-oxidation processes which is a detriment to this process. However, cost for this system is below the other systems, requiring approximately

$8,900/GJ/hr for capital costs. Operating costs have not been reported but are expected to be similar to a combustion modification process. Although the economics of this system are attractive, the preheating necessary for the $NO_x$-$NH_3$ reaction to occur and the reduced removal efficiency limit the process to a fair rating.

## $NO_x/SO_x$ SIMULTANEOUS REMOVAL

### Selective Catalytic Reduction-$NO_x/SO_2$ Removal [2]

From a $NO_x$ removal standpoint, this process is very similar to those discussed earlier. The primary difference is the additional equipment necessary to collect and process the $SO_2$. The main feature of the process is the reactor and catalyst which remove both NO and $SO_2$. This process was developed by Shell although the United States licensor, UOP, is currently marketing and developing the process. The $NO_x/SO_2$ version of the process is commonly called the SFGT process which stands for the Shell Flue Gas Treatment process.

A uniquely designed parallel flow type of reactor is used to avoid problems with particulates. The reactor consists of a series of packages containing catalyst material, arranged in a parallel configuration which allows flue gas flow between the packages. Each package consists of catalyst material placed between two layers of wire gauze. Figure 11 illustrates the internals of the parallel passage reactor. The flue gas flows between the catalyst packages and not directly through the catalyst material. This prevents plugging of the catalyst with particulate matter in the flue gas.

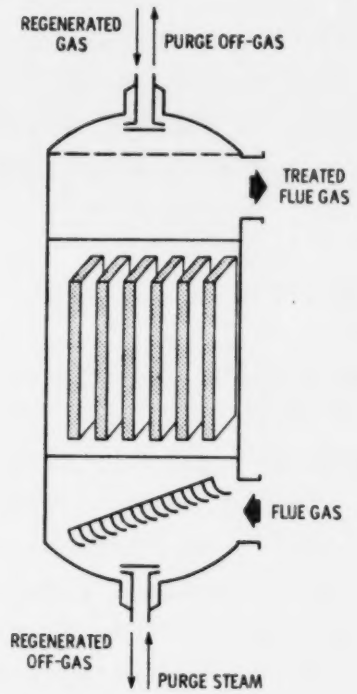



Figure 11. The SFGT parallel flow reactor [2].

The SFGT process is a dry process with two or more reactors operating in a cyclic manner. The desulfurization aspect of the process is regenerable, while $NO_x$ removal is accomplished by catalytic reduction with ammonia. The catalyst material is commonly called an acceptor since $SO_2$ removal involves adsorption or "acceptance" of $SO_2$. The desulfurization cycle consists of the following steps:

1) oxidation of acceptor bed/acceptance of $SO_2$,
2) purge reactor,
3) regeneration with reducing gas, and
4) purge reactor.

The products of the oxidation and acceptance reactions in Step 1 above catalyze the reaction of $NO_x$ with ammonia to form nitrogen and water. $NO_x$ removal is accomplished by metering ammonia into the untreated flue gas upstream of the reactors. The catalytic reaction takes place across the partially spent acceptor beds.

Simultaneous removal of $NO_x$ and $SO_x$ by a parallel flow reactor is applicable to retorting operation. However, such a system may not be warranted since the off-gases do not contain large amounts of $SO_x$ when compared to some boiler processes. Those units have been tested full scale in Japan but some process operations have yet to be fully operational. Removal efficiency is similar to other SCR processes at 90 percent for $NO_x$ and also can remove 90 percent of the $SO_x$ in the gas emissions. Cost for this type of unit is high. Capital costs are aporoximately $130,000/GJ/hr and operating costs are even three times that of a similar SCR-$NO_x$ only unit (1,400 mills/GJ). Overall rating is fair because of the data gaps in the testing and the high cost for purchase and operation.

Adsorption [2]

The adsorption process removes $NO_x$ and $SO_2$ from flue gas by adsorbing them onto a special activated char. Adsorbed $NO_x$ is reduced to $N_2$ while $SO_2$ is reduced and condensed to an elemental sulfur by-product. Flue gas is taken from the boiler air preheater and passed through a particulate removal device to prevent blinding of the adsorption bed. The flue gas then enters the adsorber, a vertical column with parallel louver beds containing the char in pellet form. $NO_x$ and $SO_2$ are adsorbed on the char which slowly moves downward through the bed.

The reaction product is held in the pores of the char pellets. The flue gas exits the adsorber and passes to the stack. The saturated char leaves the bottom of the adsorber and is screened to remove any fly ash deposits. It is then conveyed to a regenerator where it is mixed with hot sand (650°C).

The primary drawback of this process, besides the low $NO_x$ removal level, is its complexity: numerous process steps involving hot solids handling. Solids flow can be difficult to control and high maintenance requirements could be expected. The vendor has reported several mechanical problems during testing which included control of adsorber-bed levels, poor char distribution, char-sand separation, hot sand conveying, and char cooling and feed. Some corrosion-resistant material is needed in the high temperature zones of the process. The ash waste stream from the off-gas treatment reactor appears to be the sole secondary pollutant associated with the process. The overall complexity and low $NO_x$ removal of the process present definite technical disadvantages.

Removal of $NO_x$ by adsorption is marginally applicable to retorting operations because of the potential for plugging by particulates and the quantity of $SO_x$ required in the emissions. The process is considered primarily a $SO_x$ removal process with $NO_x$ removal secondary. This process is currently being tested on a prototype scale. $NO_x$ removal is low averaging 40 to 60 percent. $SO_x$ removal is 80 to 95 percent. Economically the cost of this unit is $60,000/GJ/hr for capital cost and 640 mills/GJ for operation. Because of its limited applicability and removal efficiency, its current status of development, and its high cost, this technology is a poor choice for testing at oil shale facilities.

Electron Beam Radiation [2]

This dry process utilizes an electron beam to bombard the flue gas, removing $NO_x$ and $SO_2$ in the process. A block diagram for the process is shown in Figure 12.

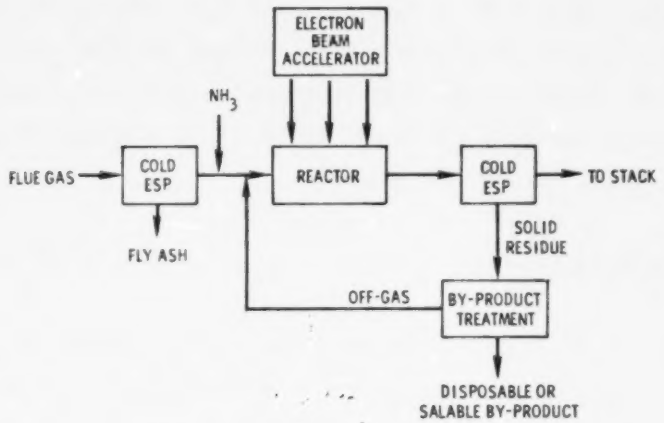



Figure 12. Process flow diagram for Ebara-JAERI electron beam process [2].

Flue gas is passed through a cold ESP to remove particulates. After a small amount of ammonia is added, the gas enters a reactor where it is bombarded with an electron beam. (The penetration of the gas stream by the beam will require a unique discharge pattern or other special design considerations.) A powder containing both ammoinum nitrate and sulfate is generated by an unknown reaction mechanism [20]. The gas then exits the reactor, passes through a second ESP to remove the solid by-product, and is sent to the stack. The by-product treatment system is still being developed. Various methods investigated include thermal decomposition in the presence of an inert gas, steam roasting with CaO, or steam roasting with $H_2O$. The by-product may eventually be useful as a fertilizer.

This process has some applicability to retorting operations but requires particulate removal prior to treatment. Currently being tested on a pilot scale, it is capable of removing 80 percent of the $NO_x$ in a stream and a comparable amount of $SO_x$. Economically the unit would require about $60,000/GJ/hr capital cost. Operating costs are unknown but the process requires approximately 3 percent of the boiler equivalent energy. The unit is only applicable to gas streams with comparable $NO_x$ and $H_2O$ concentrations and this may require steam to be added to the process. Development status, high cost, and moderate removal limit this technology to a poor rating at this time with a possibility of a fair rating with further development.

Absorption Reduction [2]

Absorption-reduction processes simultaneously remove $NO_x$ and $SO_2$ from flue gas by absorbing them into a scrubbing solution. The processes are based on the use of chelating compounds, such as ethylenediamine tetraacedic acid (EDTA) complexed with iron, to "catalyze" the absorption of $NO_x$. Most process vendors prefer a perforated-plate type of gas-liquid contractor because of easier cleaning, wider operating ranges, and more economical handling of high liquid rates. Most absorption-reduction processes utilize ferrous chelating compounds to enhance NO absorption but differ in the scrubbing solution, by-product treatment, and sorbent regeneration.

Applicability of this process is fair. An $SO_x$:$NO_x$ ratio of 3-5 is required for maximum performance which cannot be attained at some retorts according to process estimates shown in Table 12. Development is still on a pilot scale. Removal efficiency for $NO_x$ and $SO_x$ is 80 percent and 90 percent, respectively. Economics are more favorable than for other simultaneous processes but are still significantly higher than for $NO_x$-only control

technologies. Water is used as a scrubbing liquor and may result in a large wastewater stream due to the high liquid rate that is required. Although this process has excellent potential for simultaneous removal, current development status, required $SO_x$:$NO_x$ ratio and overall cost must be overcome.

Oxidation-Absorption-Reduction [2]

Oxidation-absorption-reduction processes simultaneously remove $NO_x$ and $SO_2$ from flue gas by oxidizing relatively insoluble NO to relatively soluble $NO_2$ and then absorbing both $NO_2$ and $SO_2$ into a scrubbing solution. The processes are based on the use of gas-phase oxidants, either ozone ($O_3$) or chlorine dioxide ($ClO_2$), to selectively oxidize NO and $NO_2$. Both perforated-plate and packed bed absorption columns are utilized by various process vendors.

Most of the oxidation-absorption-reduction processes are similar in that they consist of five major sections:

- prescrubbing
- gas-phase oxidation
- $NO_x/SO_2$ absorption
- reduction of absorbed $NO_x$ and oxidation of $SO_3^=$
- wastewater treatment

The areas where process differ are gas-phase oxidation - $O_3$ or $ClO_2$; absorption solutions - limestone slurry ($CaCO_3$), $H_2SO_4$, or NaOH; and the amount and type of waste treatment required. Thermal decomposition, biological denitrification, or wastewater evaporation wastewater treatment systems can be used. Because of these differences, only one of the oxidation-absorption-reduction processes, that of Mitsubishi Heavy Industries, is examined here in detail (Figure 13).

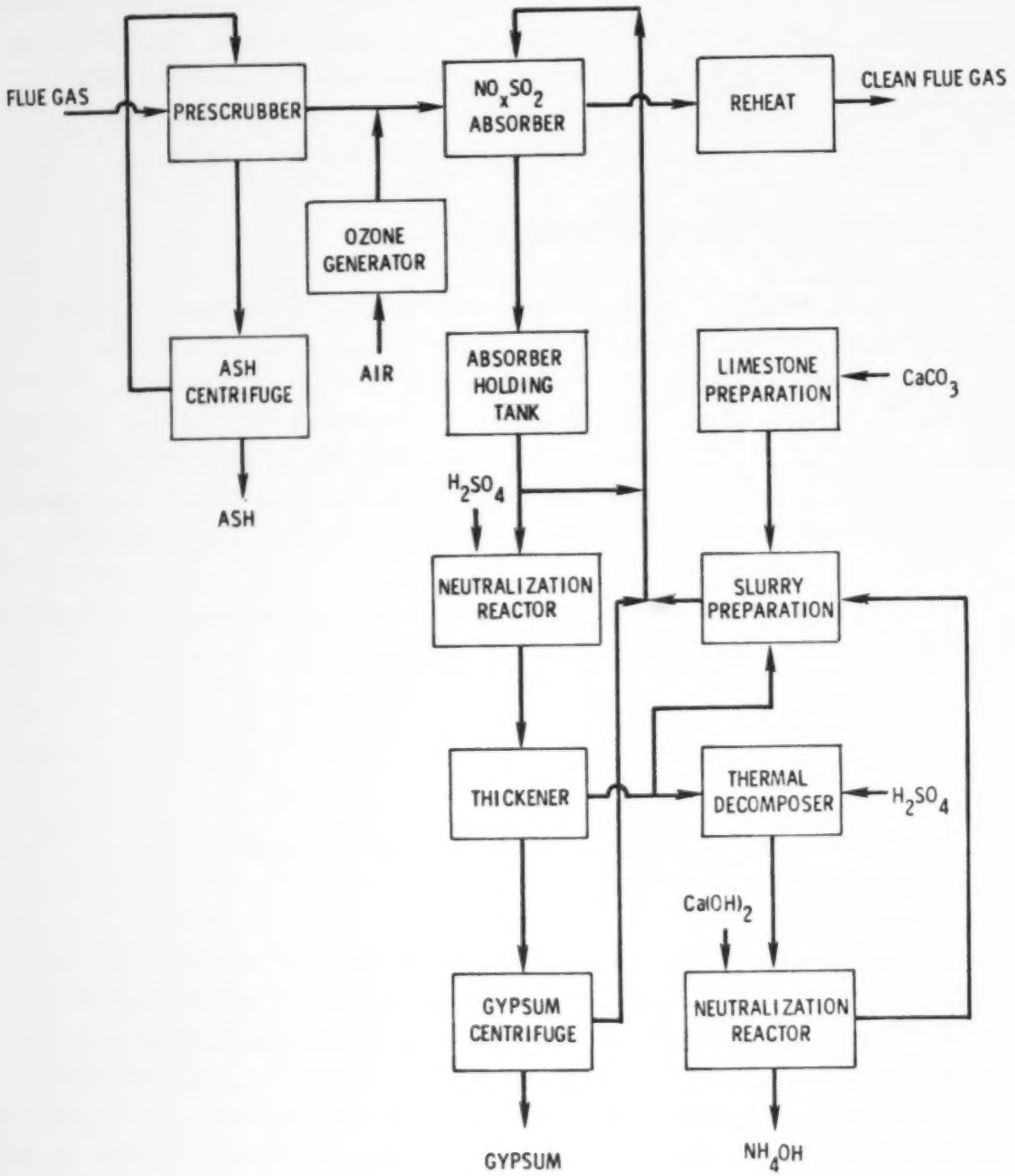



Figure 13. Process flow diagram for MHI oxidation-absorption-reduction process [2].

Oxidation-absorption-reduction systems are applicable to oil shale retorting processes. However, this technology is still in prototype development. Preliminary tests indicate that 90 percent removal is attainable with a similar reduction of $SO_x$. Capital costs are approximately $64,000/GJ/hr. Energy requirements are high (5-10% of energy output) because of the large amounts of liquid required to be moved. Water usage is high and is a limiting factor. This process is given a poor rating because of its current development status, high cost, and use of large amounts of water.

Oxidation-Absorption [2]

As a group, oxidation-absorption processes include those oxidation processes which do not qualify for the oxidation-absorption-reduction category. Basically, there are two types of oxidation-absorption processes. One is a simplified version of the oxidation-absorption-reduction process and uses an excess of ozone to selectively oxidize $NO_x$ to $N_2O_5$ which is absorbed into aqueous solution and concentrated to form a 60 percent nitric acid ($HNO_3$) by-product. There is no reduction of $NO_x$($NO_2$) by the absorption of $SO_2$(as $SO_3^=$) and wastewater treatment facility. The other type of oxidation-absorption process is based on equimolar $NO$-$NO_2$ absorption: absorbing $N_2O_3$ which is formed by the gas-phase reaction of NO and $NO_2$.

This process appears to be applicable to retorting processes. However, the process is only being tested on a pilot scale and exact requirements of a large control device are not known. Removal efficiency of 90 percent indicates good potential. Costs are unknown due to limited development but energy costs are estimated at 5-10 percent of the equivalent boiler energy. The process uses large amounts of water and may create significant

secondary pollutant impacts. Development status of this process limit it to a poor rating for current testing on retorting processes.

Table 19 summarizes previous discussions on the 11 major $NO_x$ control technologies. Only two technologies have a good rating with three other technologies rated fair. Selective catalytic reduction using a fixed bed reactor was rated fair because of the potential plugging problem that reduces its applicability. Selective noncatalytic reduction was eliminated from final consideration because of its moderate removal efficiency. Simultaneous removal of $NO_x$ and $SO_x$ by an SCR parallel flow reactor had a high cost relative to the other technologies. The two technologies that remain for final consideration are the selective catalytic reduction moving bed and parallel flow reactors. Both of these technologies have good potential applicability to retorting process and are currently used on oil-fired boilers which will be similar to those operations on the development sites. Both technologies can control over 90 percent of the $NO_x$ in a gas stream and have a low cost when compared to other FGT technologies. In addition, each technology offers some individual advantages. The moving bed reactor can remove up to 70 percent of the particulate matter in a gas stream. This advantage may reduce the amount of pollution control equipment necessary at a development. The parallel flow reactor is slightly less expensive initially and has a lower operating cost. This reactor is also not susceptible to plugging as the moving bed reactor which may reduce down time. The parallel flow reactor system is also a less complex system than the moving bed reactor. Thus, the best choice for pilot scale development at retorting operations is the selective catalytic reduction-parallel flow reactor system.

# TABLE 19. EVALUATION OF $NO_x$ FLUE GAS TREATMENT TECHNOLOGIES [1,2,26]

| Flue gas treatment | Applicability to oil shale retorting operations | Status of development | Removal efficiency, % | Economics | Use of water | Scenario III rating |
|---|---|---|---|---|---|---|
| | | | $NO_x$ removal only | | | |
| Selective catalytic reduction (SCR) | | | | | | |
| - Fixed bed reactor | Applicable but cannot be used with particulate loadings due to severe plugging | Available in Japan | >90 | Fixed cost: $19,400/GJ/hr<br>Operating cost: 530 mills/GJ<br>Requires 1.2% of energy output[a], large ΔP | None | Fair |
| - Moving bed reactor | Applicable but cannot be used with large particulate loadings | Available in Japan | >90 | Fixed cost: $19,400/GJ/hr<br>Operating cost: 500 mills/GJ<br>Requires <1% of energy output[a], low ΔP | None | Good |
| - Parallel flow reactor | Applicable to retort operations | Available in Japan | >90 | Fixed cost: $10,800/GJ/hr<br>Operating cost: 420 mills/GJ<br>Requires 0.2% of energy output[a], moderate ΔP | None | Good |
| Adsorption-oxidation | Applicable only if operated with an $SO_x$ scrubber | Pilot-scale | 85 | Fixed and operating costs unknown<br>Requires approximately 3% of total energy output | Requires water<br>Generates wastewater | Poor |
| Selective noncatalytic reduction | Applicable to most processes | Available in Japan | 40-60 | Fixed cost: $8,900/GJ/hr<br>Operating cot: Unknown | None | Fair |
| | | | $NO_x/SO_x$ simultaneous removal | | | |
| SCR-parallel flow reactor | Applicable | Full-scale tests in Japan | 90 | Fixed cost: $130,000/GJ/hr<br>Operating cost: 1400 mills/GJ<br>Requires 1.5% of energy output | None | Fair |
| Adsorption | Cannot be used wth high particulate loadings | One prototype tested on coal | 60 | Fixed cost: $60,000/GJ/hr[a]<br>Operating cost: 640 mills/GJ<br>Requires 2% of energy output, large ΔP | None | Poor |
| Electron beam radiation | Requires $H_2O$ concentration greater than $NO_x$ concentration, need particulate removal | Pilot-scale | 80 | Fixed cost: $60,000/GJ/hr[a]<br>Operating cost: Unknown<br>Requires 3.3% of energy output | Possible | Poor |
| Absorption-reduction | Requires $SO_x$:$NO_x$ ratio of greater than 2.5 | Pilot-scale | 85 | Fixed cost: $52,000/GJ/hr<br>Operating cost: $1,500/GJ<br>Requires 1.8% of energy output, large ΔP | Uses water<br>Generates wastewater | Poor |
| Oxidation-absorption-reduction | Applicable to most processes | Protogype | 90 | Fixed cost: $64,000/GJ/hr<br>Operating cot: $1,800/GJ<br>Requires 5-10% of energy output, large ΔP | Uses large amounts of water. Generates wastewater | Poor |
| Oxidation-absorption | Applicable to most processes | Pilot-scale | 90 | Fixed cost: Unknown<br>Operating cost: Unknown<br>Requires 5-10% of energy output, large ΔP | Uses large amounts of water. Generates wastewater | Poor |

[a]Based on estimate from a coal-fired boiler.

## Uncertainties in Designing SCR Systems

Several uncertainties exist in the design of an SCR parallel flow pilot unit. Catalysts that are resistant to sulfur species are patented or are considered trade secrets by Japanese firms. Parallel flow reactor design may also be controlled by these companies. However, Japanese SCR processes are currently being pilot-tested at three sites in the United States and a full-scale unit is being installed at a California utility.[a] In addition, the EPA has studied SCR processes on a 2,500 scfm pilot plant in California and demonstrated 90% $NO_x$ removal with gas firing and 50% $NO_x$ removal with oil firing. This EPA contractor designed and constructed this unit, which demonstrates that design of a similar unit is possible. Acquisition of a Japanese-designed pilot plant may also be feasible and should be investigated.[a]

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[a]Personal communication with H. S. Rosenberg, Battelle Columbus Laboratories, April 29, 1981.

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# APPENDIX A

## STABILITY WIND ROSE (STAR) DATA USED FOR MODELING FIVE OIL SHALE DEVELOPMENTS IN THE PICEANCE BASIN

## TABLE A-1. STAR DATA FOR RIO BLANCO

| STABILITY | SPD(MPS) WIND DIR | 0.670 | 2.450 | 4.470 | 6.930 | 9.610 | 12.520 |
|---|---|---|---|---|---|---|---|
| A | N | 0.0 | 0.0004 | 0.0023 | 0.0001 | 0.0 | 0.0 |
| A | NNE | 0.0 | 0.0003 | 0.0013 | 0.0003 | 0.0 | 0.0 |
| A | NE | 0.0001 | 0.0003 | 0.0019 | 0.0001 | 0.0 | 0.0 |
| A | ENE | 0.0 | 0.0007 | 0.0005 | 0.0 | 0.0 | 0.0 |
| A | E | 0.0 | 0.0003 | 0.0001 | 0.0 | 0.0 | 0.0 |
| A | ESE | 0.0001 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | SE | 0.0 | 0.0004 | 0.0003 | 0.0 | 0.0 | 0.0 |
| A | SSE | 0.0 | 0.0001 | 0.0001 | 0.0 | 0.0001 | 0.0 |
| A | S | 0.0 | 0.0003 | 0.0020 | 0.0033 | 0.0007 | 0.0 |
| A | SSW | 0.0001 | 0.0001 | 0.0101 | 0.0187 | 0.0012 | 0.0 |
| A | SW | 0.0 | 0.0008 | 0.0076 | 0.0025 | 0.0 | 0.0 |
| A | WSW | 0.0 | 0.0007 | 0.0073 | 0.0012 | 0.0 | 0.0 |
| A | W | 0.0 | 0.0007 | 0.0061 | 0.0046 | 0.0007 | 0.0 |
| A | WNW | 0.0001 | 0.0008 | 0.0052 | 0.0029 | 0.0001 | 0.0 |
| A | NW | 0.0001 | 0.0008 | 0.0028 | 0.0029 | 0.0 | 0.0 |
| A | NNW | 0.0 | 0.0005 | 0.0023 | 0.0003 | 0.0 | 0.0 |
| B | N | 0.0 | 0.0004 | 0.0008 | 0.0003 | 0.0 | 0.0 |
| B | NNE | 0.0 | 0.0004 | 0.0008 | 0.0003 | 0.0 | 0.0 |
| B | NE | 0.0 | 0.0015 | 0.0009 | 0.0 | 0.0 | 0.0 |
| B | ENE | 0.0 | 0.0004 | 0.0003 | 0.0 | 0.0 | 0.0 |
| B | E | 0.0 | 0.0007 | 0.0001 | 0.0 | 0.0 | 0.0 |
| B | ESE | 0.0 | 0.0003 | 0.0 | 0.0 | 0.0 | 0.0 |
| B | SE | 0.0001 | 0.0004 | 0.0003 | 0.0 | 0.0 | 0.0 |
| B | SSE | 0.0001 | 0.0001 | 0.0 | 0.0 | 0.0 | 0.0 |
| B | S | 0.0 | 0.0007 | 0.0008 | 0.0008 | 0.0 | 0.0 |
| B | SSW | 0.0 | 0.0001 | 0.0023 | 0.0033 | 0.0004 | 0.0 |
| B | SW | 0.0 | 0.0008 | 0.0011 | 0.0004 | 0.0 | 0.0 |
| B | WSW | 0.0 | 0.0009 | 0.0027 | 0.0005 | 0.0 | 0.0 |
| B | W | 0.0001 | 0.0009 | 0.0015 | 0.0007 | 0.0 | 0.0 |
| B | WNW | 0.0001 | 0.0009 | 0.0015 | 0.0007 | 0.0 | 0.0001 |
| B | NW | 0.0 | 0.0009 | 0.0013 | 0.0005 | 0.0001 | 0.0 |
| B | NNW | 0.0 | 0.0009 | 0.0008 | 0.0 | 0.0 | 0.0 |
| C | N | 0.0 | 0.0003 | 0.0008 | 0.0 | 0.0 | 0.0 |
| C | NNE | 0.0 | 0.0004 | 0.0001 | 0.0001 | 0.0001 | 0.0 |
| C | NE | 0.0 | 0.0019 | 0.0007 | 0.0001 | 0.0 | 0.0 |
| C | ENE | 0.0 | 0.0033 | 0.0003 | 0.0 | 0.0 | 0.0 |
| C | E | 0.0 | 0.0029 | 0.0 | 0.0 | 0.0 | 0.0 |
| C | ESE | 0.0 | 0.0009 | 0.0001 | 0.0 | 0.0 | 0.0 |
| C | SE | 0.0 | 0.0011 | 0.0001 | 0.0 | 0.0 | 0.0 |
| C | SSE | 0.0 | 0.0003 | 0.0001 | 0.0 | 0.0 | 0.0 |
| C | S | 0.0 | 0.0003 | 0.0015 | 0.0007 | 0.0003 | 0.0 |
| C | SSW | 0.0 | 0.0013 | 0.0044 | 0.0021 | 0.0005 | 0.0 |
| C | SW | 0.0 | 0.0009 | 0.0020 | 0.0001 | 0.0 | 0.0 |
| C | WSW | 0.0001 | 0.0007 | 0.0032 | 0.0005 | 0.0 | 0.0 |
| C | W | 0.0001 | 0.0003 | 0.0017 | 0.0004 | 0.0001 | 0.0 |
| C | WNW | 0.0 | 0.0011 | 0.0009 | 0.0009 | 0.0001 | 0.0 |
| C | NW | 0.0001 | 0.0009 | 0.0007 | 0.0008 | 0.0001 | 0.0 |

(continued)

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TABLE A-1 (continued)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| C | NNW | 0.0 | 0.0007 | 0.0008 | 0.0003 | 0.0 | 0.0 |
| D | N | 0.0015 | 0.0046 | 0.0032 | 0.0004 | 0.0016 | 0.0 |
| D | NNE | 0.0013 | 0.0049 | 0.0044 | 0.0013 | 0.0009 | 0.0 |
| D | NE | 0.0048 | 0.0065 | 0.0024 | 0.0003 | 0.0 | 0.0 |
| D | ENE | 0.0035 | 0.0100 | 0.0 | 0.0 | 0.0 | 0.0 |
| D | E | 0.0027 | 0.0061 | 0.0 | 0.0 | 0.0 | 0.0 |
| D | ESE | 0.0016 | 0.0028 | 0.0003 | 0.0 | 0.0 | 0.0 |
| D | SE | 0.0020 | 0.0032 | 0.0007 | 0.0001 | 0.0 | 0.0 |
| D | SSE | 0.0023 | 0.0053 | 0.0016 | 0.0001 | 0.0 | 0.0 |
| D | S | 0.0020 | 0.0082 | 0.0069 | 0.0021 | 0.0015 | 0.0003 |
| D | SSW | 0.0023 | 0.0117 | 0.0135 | 0.0089 | 0.0009 | 0.0001 |
| D | SW | 0.0017 | 0.0121 | 0.0108 | 0.0017 | 0.0 | 0.0 |
| D | WSW | 0.0012 | 0.0113 | 0.0159 | 0.0070 | 0.0003 | 0.0 |
| D | W | 0.0024 | 0.0065 | 0.0092 | 0.0069 | 0.0025 | 0.0003 |
| D | WNW | 0.0016 | 0.0033 | 0.0039 | 0.0019 | 0.0011 | 0.0003 |
| D | NW | 0.0021 | 0.0035 | 0.0028 | 0.0013 | 0.0 | 0.0 |
| D | NNW | 0.0005 | 0.0024 | 0.0025 | 0.0008 | 0.0001 | 0.0 |
| E | N | 0.0045 | 0.0023 | 0.0027 | 0.0008 | 0.0001 | 0.0 |
| E | NNE | 0.0032 | 0.0037 | 0.0016 | 0.0001 | 0.0 | 0.0 |
| E | NE | 0.0048 | 0.0016 | 0.0008 | 0.0 | 0.0 | 0.0 |
| E | ENE | 0.0077 | 0.0020 | 0.0 | 0.0 | 0.0 | 0.0 |
| E | E | 0.0052 | 0.0024 | 0.0 | 0.0 | 0.0 | 0.0 |
| E | ESE | 0.0036 | 0.0015 | 0.0001 | 0.0 | 0.0 | 0.0 |
| E | SE | 0.0056 | 0.0029 | 0.0005 | 0.0 | 0.0 | 0.0 |
| E | SSE | 0.0084 | 0.0070 | 0.0009 | 0.0 | 0.0 | 0.0 |
| E | S | 0.0113 | 0.0131 | 0.0037 | 0.0012 | 0.0001 | 0.0 |
| E | SSW | 0.0132 | 0.0236 | 0.0139 | 0.0027 | 0.0001 | 0.0 |
| E | SW | 0.0174 | 0.0429 | 0.0102 | 0.0012 | 0.0 | 0.0 |
| E | WSW | 0.0131 | 0.0339 | 0.0404 | 0.0092 | 0.0028 | 0.0004 |
| E | W | 0.0136 | 0.0181 | 0.0167 | 0.0106 | 0.0027 | 0.0007 |
| E | WNW | 0.0144 | 0.0199 | 0.0050 | 0.0033 | 0.0001 | 0.0001 |
| E | NW | 0.0089 | 0.0085 | 0.0024 | 0.0007 | 0.0 | 0.0 |
| E | NNW | 0.0063 | 0.0048 | 0.0027 | 0.0007 | 0.0 | 0.0 |
| F | N | 0.0011 | 0.0001 | 0.0 | 0.0009 | 0.0007 | 0.0 |
| F | NNE | 0.0017 | 0.0003 | 0.0 | 0.0001 | 0.0001 | 0.0 |
| F | NE | 0.0004 | 0.0001 | 0.0 | 0.0003 | 0.0 | 0.0 |
| F | ENE | 0.0004 | 0.0001 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | E | 0.0011 | 0.0003 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | ESE | 0.0005 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | SE | 0.0001 | 0.0001 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | SSE | 0.0011 | 0.0003 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | S | 0.0017 | 0.0011 | 0.0004 | 0.0003 | 0.0 | 0.0 |
| F | SSW | 0.0024 | 0.0024 | 0.0009 | 0.0007 | 0.0 | 0.0 |
| F | SW | 0.0015 | 0.0065 | 0.0032 | 0.0001 | 0.0 | 0.0 |
| F | WSW | 0.0010 | 0.0084 | 0.0228 | 0.0037 | 0.0 | 0.0 |
| F | W | 0.0019 | 0.0035 | 0.0084 | 0.0003 | 0.0001 | 0.0 |
| F | WNW | 0.0019 | 0.0046 | 0.0032 | 0.0001 | 0.0 | 0.0 |
| F | NW | 0.0018 | 0.0045 | 0.0015 | 0.0 | 0.0 | 0.0 |
| F | NNW | 0.0005 | 0.0012 | 0.0007 | 0.0 | 0.0 | 0.0 |

Data is a reduction of the data presented in: Rio Blanco Oil Shale Company, Denver, Colorado, Modular Development Phase Monitoring Report Three, Volume 2, March 31, 1979.

TABLE A-2. STAR DATA FOR LONG RIDGE

| STABILITY | SPD(MPS) WIND DIR | 1.000 | 2.600 | 4.400 | 6.550 | 5.780 | 12.870 |
|---|---|---|---|---|---|---|---|
| A | N | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | NNE | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | NE | 0.0007 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | ENE | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | E | 0.0012 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | ESE | 0.0007 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | SE | 0.0 | 0.0002 | 0.0002 | 0.0 | 0.0 | 0.0 |
| A | SSE | 0.0002 | 0.0 | 0.0002 | 0.0 | 0.0 | 0.0 |
| A | S | 0.0010 | 0.0005 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | SSW | 0.0 | 0.0002 | 0.0002 | 0.0 | 0.0 | 0.0 |
| A | SW | 0.0 | 0.0 | 0.0002 | 0.0 | 0.0 | 0.0 |
| A | WSW | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| A | W | 0.0014 | 0.0010 | 0.0007 | 0.0012 | 0.0 | 0.0 |
| A | WNW | 0.0060 | 0.0010 | 0.0014 | 0.0002 | 0.0 | 0.0 |
| A | NW | 0.0022 | 0.0002 | 0.0005 | 0.0 | 0.0 | 0.0 |
| A | NNW | 0.0022 | 0.0002 | 0.0002 | 0.0 | 0.0 | 0.0 |
| B | N | 0.0010 | 0.0 | 0.0002 | 0.0 | 0.0 | 0.0 |
| B | NNE | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| B | NE | 0.0 | 0.0005 | 0.0 | 0.0 | 0.0 | 0.0 |
| B | ENE | 0.0005 | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 |
| B | E | 0.0010 | 0.0017 | 0.0003 | 0.0 | 0.0 | 0.0 |
| B | ESE | 0.0010 | 0.0034 | 0.0014 | 0.0 | 0.0 | 0.0 |
| B | SE | 0.0005 | 0.0022 | 0.0039 | 0.0002 | 0.0 | 0.0 |
| B | SSE | 0.0019 | 0.0048 | 0.0036 | 0.0 | 0.0 | 0.0 |
| B | S | 0.0019 | 0.0034 | 0.0055 | 0.0010 | 0.0 | 0.0 |
| B | SSW | 0.0005 | 0.0014 | 0.0022 | 0.0017 | 0.0 | 0.0 |
| B | SW | 0.0003 | 0.0010 | 0.0005 | 0.0 | 0.0 | 0.0 |
| B | WSW | 0.0006 | 0.0014 | 0.0024 | 0.0002 | 0.0 | 0.0 |
| B | W | 0.0026 | 0.0024 | 0.0024 | 0.0007 | 0.0 | 0.0 |
| B | WNW | 0.0041 | 0.0022 | 0.0024 | 0.0014 | 0.0005 | 0.0 |
| B | NW | 0.0017 | 0.0007 | 0.0002 | 0.0007 | 0.0 | 0.0 |
| B | NNW | 0.0005 | 0.0005 | 0.0002 | 0.0005 | 0.0 | 0.0 |
| C | N | 0.0041 | 0.0005 | 0.0014 | 0.0005 | 0.0002 | 0.0 |
| C | NNE | 0.0007 | 0.0005 | 0.0002 | 0.0 | 0.0 | 0.0 |
| C | NE | 0.0022 | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 |
| C | ENE | 0.0014 | 0.0012 | 0.0002 | 0.0 | 0.0 | 0.0 |
| C | E | 0.0051 | 0.0036 | 0.0010 | 0.0 | 0.0 | 0.0 |
| C | ESE | 0.0073 | 0.0077 | 0.0031 | 0.0005 | 0.0 | 0.0 |
| C | SE | 0.0063 | 0.0087 | 0.0017 | 0.0 | 0.0 | 0.0 |
| C | SSE | 0.0101 | 0.0079 | 0.0026 | 0.0 | 0.0 | 0.0 |
| C | S | 0.0106 | 0.0065 | 0.0034 | 0.0013 | 0.0 | 0.0 |
| C | SSW | 0.0028 | 0.0017 | 0.0048 | 0.0019 | 0.0 | 0.0 |
| C | SW | 0.0017 | 0.0022 | 0.0017 | 0.0 | 0.0 | 0.0 |
| C | WSW | 0.0025 | 0.0029 | 0.0024 | 0.0002 | 0.0 | 0.0 |
| C | W | 0.0061 | 0.0046 | 0.0084 | 0.0017 | 0.0010 | 0.0 |
| C | WNW | 0.0070 | 0.0079 | 0.0108 | 0.0055 | 0.0002 | 0.0 |
| C | NW | 0.0034 | 0.0017 | 0.0019 | 0.0017 | 0.0002 | 0.0 |

(continued)

TABLE A-2 (continued)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| C | NNW | 0.0036 | 0.0012 | 0.0019 | 0.0014 | 0.0002 | 0.0 |
| D | N | 0.0070 | 0.0017 | 0.0017 | 0.0005 | 0.0 | 0.0 |
| D | NNE | 0.0014 | 0.0 | 0.0002 | 0.0002 | 0.0 | 0.0 |
| D | NE | 0.0014 | 0.0002 | 0.0012 | 0.0 | 0.0 | 0.0 |
| D | ENE | 0.0026 | 0.0026 | 0.0019 | 0.0 | 0.0 | 0.0 |
| D | E | 0.0072 | 0.0022 | 0.0010 | 0.0 | 0.0 | 0.0 |
| D | ESE | 0.0087 | 0.0039 | 0.0012 | 0.0002 | 0.0 | 0.0 |
| D | SE | 0.0046 | 0.0014 | 0.0002 | 0.0 | 0.0 | 0.0 |
| D | SSE | 0.0048 | 0.0031 | 0.0005 | 0.0 | 0.0 | 0.0 |
| D | S | 0.0092 | 0.0031 | 0.0017 | 0.0014 | 0.0 | 0.0 |
| D | SSW | 0.0014 | 0.0010 | 0.0029 | 0.0007 | 0.0 | 0.0 |
| D | SW | 0.0012 | 0.0014 | 0.0012 | 0.0 | 0.0 | 0.0 |
| D | WSW | 0.0026 | 0.0022 | 0.0012 | 0.0 | 0.0 | 0.0 |
| D | W | 0.0082 | 0.0041 | 0.0063 | 0.0065 | 0.0005 | 0.0 |
| D | WNW | 0.0137 | 0.0123 | 0.0113 | 0.0036 | 0.0002 | 0.0 |
| D | NW | 0.0077 | 0.0041 | 0.0039 | 0.0012 | 0.0002 | 0.0 |
| D | NNW | 0.0060 | 0.0041 | 0.0031 | 0.0019 | 0.0007 | 0.0 |
| E | N | 0.0209 | 0.0014 | 0.0005 | 0.0012 | 0.0002 | 0.0 |
| E | NNE | 0.0084 | 0.0007 | 0.0005 | 0.0 | 0.0 | 0.0 |
| E | NE | 0.0065 | 0.0017 | 0.0 | 0.0 | 0.0 | 0.0 |
| E | ENE | 0.0051 | 0.0026 | 0.0014 | 0.0 | 0.0 | 0.0 |
| E | E | 0.0149 | 0.0039 | 0.0007 | 0.0 | 0.0 | 0.0 |
| E | ESE | 0.0099 | 0.0039 | 0.0002 | 0.0 | 0.0 | 0.0 |
| E | SE | 0.0067 | 0.0014 | 0.0002 | 0.0 | 0.0 | 0.0 |
| E | SSE | 0.0075 | 0.0014 | 0.0010 | 0.0 | 0.0 | 0.0 |
| E | S | 0.0128 | 0.0029 | 0.0012 | 0.0002 | 0.0 | 0.0 |
| E | SSW | 0.0075 | 0.0010 | 0.0022 | 0.0010 | 0.0 | 0.0 |
| E | SW | 0.0041 | 0.0010 | 0.0010 | 0.0 | 0.0 | 0.0 |
| E | WSW | 0.0043 | 0.0019 | 0.0012 | 0.0007 | 0.0 | 0.0 |
| E | W | 0.0195 | 0.0108 | 0.0079 | 0.0077 | 0.0012 | 0.0005 |
| E | WNW | 0.0655 | 0.0356 | 0.0214 | 0.0099 | 0.0007 | 0.0 |
| E | NW | 0.0417 | 0.0140 | 0.0094 | 0.0017 | 0.0002 | 0.0 |
| E | NNW | 0.0349 | 0.0084 | 0.0063 | 0.0022 | 0.0 | 0.0 |
| F | N | 0.0036 | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | NNE | 0.0014 | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | NE | 0.0017 | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | ENE | 0.0017 | 0.0002 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | E | 0.0034 | 0.0012 | 0.0002 | 0.0 | 0.0 | 0.0 |
| F | ESE | 0.0014 | 0.0012 | 0.0005 | 0.0 | 0.0 | 0.0 |
| F | SE | 0.0007 | 0.0010 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | SSE | 0.0010 | 0.0005 | 0.0 | 0.0 | 0.0 | 0.0 |
| F | S | 0.0014 | 0.0005 | 0.0010 | 0.0002 | 0.0 | 0.0 |
| F | SSW | 0.0002 | 0.0005 | 0.0012 | 0.0002 | 0.0 | 0.0 |
| F | SW | 0.0010 | 0.0 | 0.0010 | 0.0 | 0.0 | 0.0 |
| F | WSW | 0.0005 | 0.0 | 0.0002 | 0.0005 | 0.0 | 0.0 |
| F | W | 0.0017 | 0.0014 | 0.0034 | 0.0012 | 0.0 | 0.0 |
| F | WNW | 0.0089 | 0.0034 | 0.0014 | 0.0010 | 0.0 | 0.0 |
| F | NW | 0.0063 | 0.0019 | 0.0010 | 0.0002 | 0.0 | 0.0 |
| F | NNW | 0.0036 | 0.0002 | 0.0007 | 0.0 | 0.0 | 0.0 |

Data is from the Union Oil Company PSD permit application for a shale oil upgrading facility near Parachute, Colorado, September 1980.

# APPENDIX B

# AMMONIA REDUCTION PROCESSES

Nitrogen oxides control by the removal of ammonia in the retort off-gas can be accomplished by applying one of two processes, indirect or semidirect. Figures B-1 and B-2 show schematic diagrams for these processes, respectively. Both processes involve partial cooling of off-gas by direct contact with flushing liquid containing about 30% ammonia. A portion of the circulating liquid is continuously withdrawn and make up is added to the flushing-liquid cycle.

In the indirect process, the cooled gas is pumped to the ammonia scrubbers where it is washed in several countercurrent stages operating in series, first with weak ammonia solution and finally with water. The effluent weak liquor from the bottom of the scrubbers is collected, and together with a portion of flushing fluid, is pumped to the top of an ammonia distillation column, usually a bubble-plate column. This column is heated at the bottom by direct steam. The overhead vapors from the column contain ammonia, acid gases, and water vapor, and are either condensed and processed to crude concentrated ammoniacal liquor or passed through strong acid in which the ammonia is absorbed and converted to the ammonium salt. Pure concentrated ammoniacal liquor can be obtained if the acid gases are separated from the ammonia before condensation of the vapors. Before contacting the overhead vapors with the acid, part of the water vapor is removed from the gas stream by condensation in a partial condenser.

In the semidirect process, the effluent gas from the electrostatic precipitator is pumped through a reheater, then, to a "saturator" where the ammonia is removed by reaction with a strong acid, usually sulfuric acid. A portion of circulating flushing liquid is directly pumped to a distillation column. The overhead vapors

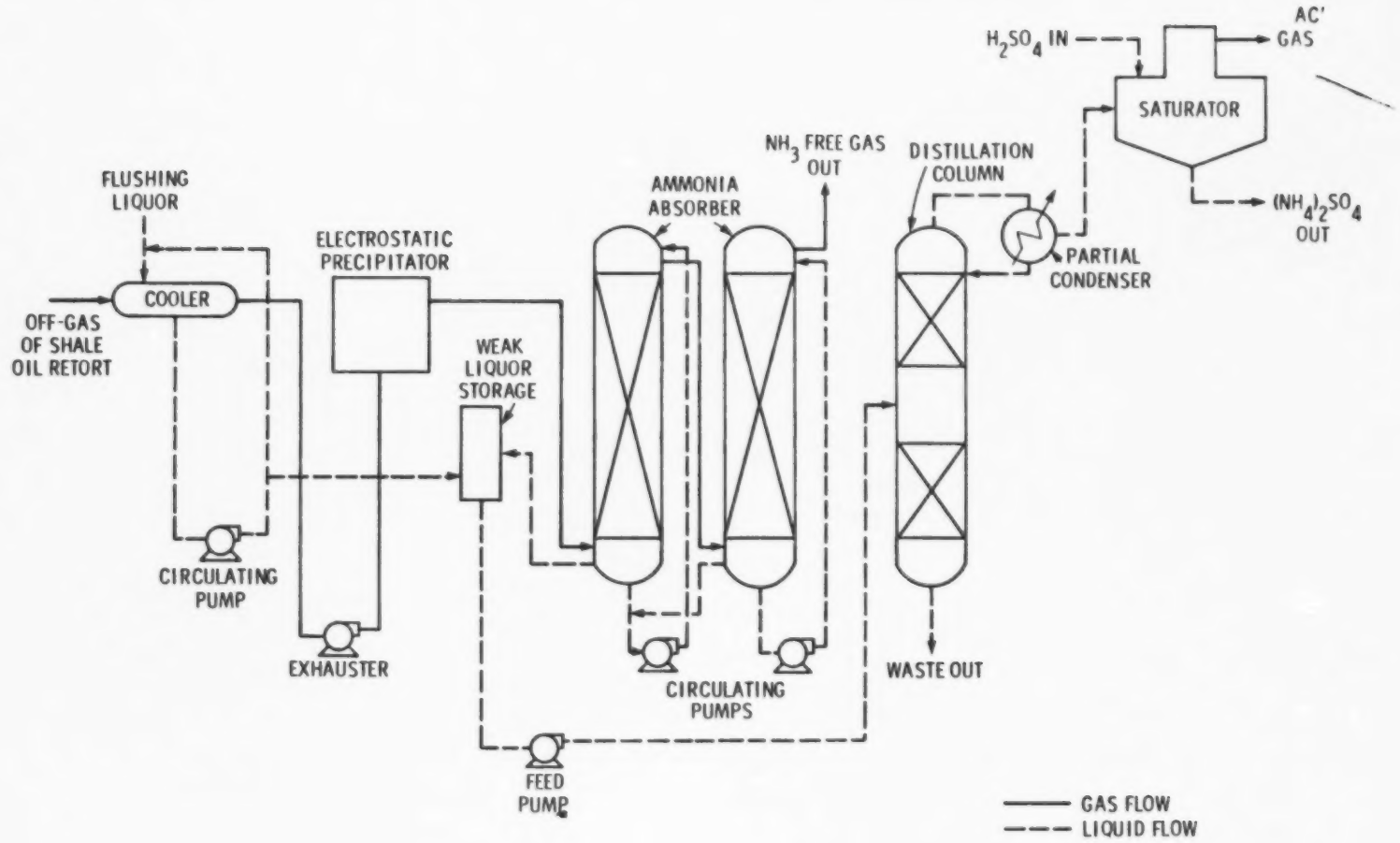


Figure B-1. Schematic diagram of a proposed indirect ammonia removal process.

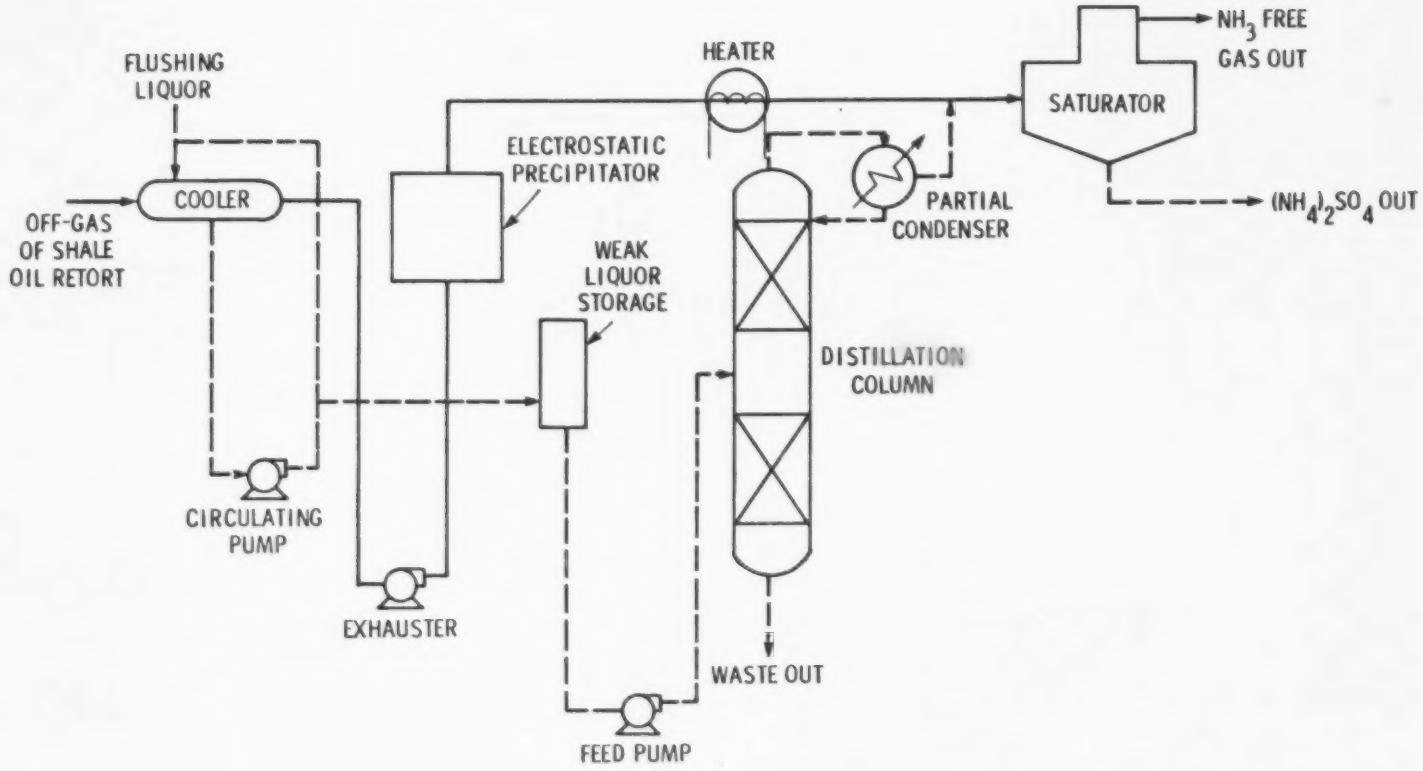


Figure B-2. Schematic diagram of a proposed semidirect ammonia removal process.

from the column are also pumped to the saturator. By comparing two processes, the indirect process has more flexibility in yielding a variety of products, its relative lack of dependence on the various process steps, and the complete removal of tar. However, high operational cost and capital investment are the biggest concern about its application.